BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: :

CONSENT MARKETS, TARIFFS AND RATES - ELECTRIC :

CONSENT MARKETS, TARIFFS AND RATES - GAS :

CONSENT ENERGY PROJECTS - HYDRO :

CONSENT ENERGY PROJECTS - CERTIFICATES :

DISCUSSION ITEMS :

STRUCK ITEMS :

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808TH COMMISSION MEETING

Hearing Room 5

Federal Energy Regulatory

Commission

888 First Street, N.E.

Washington, D.C.

Wednesday, October 9, 2002

11:05 a.m.

APPEARANCES:

COMMISSIONERS PRESENT:

CHAIRMAN PAT WOOD, III, Presiding

COMMISSIONER LINDA KEY BREATHITT

COMMISSIONER NORA MEAD BROWNELL

COMMISSIONER WILLIAM L. MASSEY

CYNTHIA MARLETTE

General Counsel of the Commission

MAGALIE R. SALAS

Secretary of the Commission

ALSO PRESENT:

JANE W. BEACH, Court Reporter

P R O C E E D I N G S

(11:05 a.m.)

CHAIRMAN WOOD: This meeting of the Federal Energy Regulatory Commission will come to order to consider the matters which have been duly posted in accordance with the Government in the Sunshine Act for this time and place.

Please join me in the Pledge to the Flag.

(Pledge of Allegiance recited.)

CHAIRMAN WOOD: We'll go right into our panel on A-3, and I'll ask the Secretary to introduce our panelists.

SECRETARY SALAS: The first panel is the panel for PJM, with the following participants: Mr. Joseph Bowring, Craig Glazer, Janice Dillard, David Kleppinger, Gregory Urbin.

Mr. Bowring will begin the presentation.

MR. BOWRING: Thank you. Good morning.

CHAIRMAN WOOD: Welcome.

MR. BOWRING: I'm, as you know, Manager of Market Monitoring for PJM. I'm here, in part because Mike Kormos is home waiting with his wife, who is expecting a baby any day; and, secondly, because Market Monitoring was asked by FERC and by PJM to look at these programs and PJM analyzed them, and to do a number of reports.

The basic issue, obviously, is that economists have recognized and everyone recognizes now, generally, that you have to have a demand-side of the market in order for everything to work. You have to have a supply and a demand.

Demand has to see the price, has to be able to react to the price in real time, and has to see a benefit or a cost as a result of reacting to that price.

The absence of DSM or any demand-side responsiveness is a flaw in the market. It's my view that it doesn't make sense to introduce additional flaws in order to correct that problem. Clearly, the issue is how do we feather in DSM without significantly impacting current market design?

In 2002, PJM had three DSM programs, fundamental DSM programs. One was ALM, or Active Load Management. There are about 1300 megawatts signed up in PJM.

Active Load Management is considered an emergency program, however, it clearly has significant economic components.

ALM is primarily a result of utilities, though not entirely utilities, paying individual customers -- or not paying them, sorry -- but permitting them not to pay a portion of their local utility rate, in return for which those customers agree to curtail up to ten times per year, in response to a signal from PJM that there is an emergency.

So there is both an economic and an emergency component. ALM actually has been, this past summer, and has been in previous summers, critical to the reliability of PJM. We call on it on a regular basis.

In addition, there was an emergency program of 510 megawatts that was signed up last summer, and again our numbers won't be final until all the metering is in in another 30 days or so, but these are preliminary numbers.

We called in the summer, this past summer, an emergency one time, and in the prior summer of 2001, we called an emergency three times, and it was significantly less. There was about 170 megawatts in 2001.

Again, this program is primarily reliability-related. However, there's also clearly an economic component. When the dispatchers determined that that emergency program is necessary for reliability, the plan provides that any participant will be paid the greater of $500 or the LMP.

The reason for that is to provide certainty to those resource as to what they will get paid when they interrupt, primarily because it is a reliability program. We want there to be no uncertainty that the megawatts will actually be reduced.

And the third program was the economic program. It was about 320 megawatts signed up in 2002 versus about 50 megawatts in 2001. There are about 26 different occasions on which economic participants implemented the program.

The economic program is triggered by LMP. Individual participants make LMP bids, at which they indicate they will get off the system, but it's not required that they do.

And individual participants respond to the LMP, their actual local marginal price, wherever they happen to be on the system. One key feature of the economic program is that there's a threshold of $75. Above $75, a participant is paid the full LMP; below $75, a participant is paid $75 less the local utility generation/transmission piece.

The rationale for that, again, is the shape of the supply curve. Payment of the G&T piece is effectively a subsidy, as any customer who gets off is clearly seeing that price, seeing that savings.

The reason for paying it above $75 is because there are clear competitive benefits above $75, based on historical -- the historical shape of the PJM supply curve. Below that, it's really not the case; it's a much flatter supply curve, much denser supply curve. It's significantly less clear that it makes sense to pay a subsidy in order to get a demand response there.

And that's my quick overview.

CHAIRMAN WOOD: Is the $75 -- this is the first summer you did the $75 or did you do the economic one at all, correct?

MR. BOWRING: No, we did have an economic program last summer. This is the first summer that we did the 475.

CHAIRMAN WOOD: Do you think the number was right? Actually, let me ask that question, first: Was there any use of that program this summer?

MR. BOWRING: There was use of it on 26 separate occasions by a large number of participants. It actually happened both above and below the $75 threshold, so we had some activity, both above and below it.

I think it's a reasonable price. Again, the actual point, the actual right point on the supply curve shifts each year, and even sometimes from day to day as the nature of the supply curve changes, but it's a reasonable measure for where that turn in the supply curve is.

CHAIRMAN WOOD: Okay, thanks.

MR. BOWRING: Thank you.

MR. GLAZER: Mr. Chairman, Commissioner Brownell, it's good to be here, and I appreciate the opportunity. Mike Kormos is actually watching on TV and between the baby and this panel, he said at the end of those, he'll let me know which was the better decision that he made.

(Laughter.)

COMMISSIONER BROWNELL: I think we know that.

MR. GLAZER: Right, right.

Well, I wanted to just take a minute. We are tag-teaming it, because I wanted to share with you, sort of a little bit of the good of the program, as well as, quite frankly, some reflection and self-criticism of what we think is needed for the future, really speaking for the Office of Interconnection with regard to some thoughts that we had going forward.

And Joe mentioned that we've had a significant increase in the amount of participation in the program this past summer, much, much more than we had the year before.

But that being said, I'm going to be the first to tell you that we're clearly not there yet with demand side, and I have been giving a lot of thought to sort of why and what are some of the issues?

I sort of, in my own mind, boil them down to -- I call it sort of the four Es or what we really need to have happen, and what we, the collective we, but ISOs, in particular, need to focus on.

One of those Es is executive talent, and I'll come back to each of these, but executive talent, emergency focus -- and I'll put that one as a question mark, as the second E, emergency focus.

The third is education, and the fourth one is sort of an entrepreneurial spirit. And let me take those one-by-one, starting with executive talent.

We have decided at PJM, and, frankly, are in the process of staffing a new Department of Demand-Side Resources. We made the determination that we really need to have at least one person, if not, in fact, an entire department of people that wake up in the morning and their job is to think about and only think about how they get demand-side resources into this marketplace and be dedicated to that, and integrate it into the markets.

So we are actually forming a new department with the Market Services Department that will be solely focused on demand-side response. We think that kind of executive focus and talent is needed.

The second E is emergency focus, and that's sort of a question mark. If you think about it, all of the programs -- I think among the three ISOs, I can speak certainly to ours -- our focus in many ways on incentives is to deal with emergencies.

In the ALM program, the Active Load Management Program, we are giving capacity payments for people to respond in emergencies. In the DSR Program, we are giving $500 megawatt hour minimum for people to respond to emergencies.

That's appropriate, but I think the demand-side response people will probably tell you that you can't build a business plan around emergencies. And as we get more and more generation being built than is being built, we are having less emergencies, which is a good thing, but actually is working counterproductive to demand-side response.

Well, it's a difficult policy issue, what do you do in that case, because it's easy -- to me, it's a no-brainer to socialize costs for demand-side in an emergency situation. Everybody benefits.

It's also -- we've made the decision, the Board and the Commission approved, socializing costs above the $75 threshold. That was really the elbow point on the price duration curve.

That was the point when having customers exercise demand response was benefitting other customers within the zone, and we said and the Board made the determination, because we didn't have membership agreement, that that was a reasonable cutting-off point to socialize some of those costs. And we appreciated the Commission's approval of that.

But maybe the focus is to move these -- all the incentives that were pouring into the emergency programs, more into the economic programs. And we're thinking about, quite frankly, maybe the ALM program needs to not be just focused on emergencies.

Right now, an industrial customer signs up and they're cut in emergency, but the don't have the ability to bid in a price. They can do it on the emergency demand-side program, but again all of the subsidies, all of the incentives go on the emergency side, not on the economic side. If we truly had the economic base, maybe we wouldn't need the emergency. So it's just one of the thoughts that we've been thinking about.

The third E is education. Clearly, customer education is needed. We, as part of forming this Department, are going to make a big push with regard to education.

It does raise a policy issue, though, of sort of what is the role of the ISO relative to the customers?

We see ourselves as the platform, but we don't want to be there competing with demand response people. We don't want to necessarily be the sole interface with the customer, because we want competition in people providing demand response.

So it's tricky, exactly how to provide that role in education and exactly what the role of the ISO is but we're absolutely committed that that that is a key part of making this a success.

And the fourth one, and I'll close with this E, is the entrepreneurial spirit of this. I personally think we all need to get a lot more entrepreneurial in how we're looking at demand-side response and not just looking at it as a regulatory issue or a regulatory problem.

For one, we shouldn't be bending the market rules just to favor demand-side response. On the other side of the coin, we shouldn't just be blaming rate caps, as therefore you can't have demand-side response because of rate caps.

I mean, I view this meeting sort of like an AA meeting, and I'll confess I had rate caps in my past. I did rate caps, as a number of you did as well, so I'm 'fessing up.

(Laughter.)

MR. GLAZER: But even with state rate caps, there is in many states, flexibility. They do not prohibit innovative rate design and new rate proposals within a rate cap.

So I don't think the fact that there are long-term rate caps, we should just throw up our hands and say that is the end of it.

And in fact we have been working with the state commission, and we want to work with the state commissions much more to sort of blend these programs. A lot of them are both state and federal, but I think we need to get beyond the rate cap issue, and not just see it as a barrier.

So let me close with those sort of those four E's again: Executive talent, which we are focused on, on getting into demand-side response; Emergency focus, and maybe getting away from that; Education; and sort of a more entrepreneurial spirit that we all have toward demand response.

Thank you.

COMMISSIONER BROWNELL: Craig, I appreciate actually the efforts that you're making to set up a separate office, because when I look at the presentations and we're still talking about demand-side as a program, it doesn't say to me that in fact we're doing what I think all the market participants have said during Standard Market Design and RTO season, which is it's an integral part of the market itself.

So while we may need flexibility so it changes depending on the conditions in the market, program suggests the old pilot, the old temporary. And I think it's difficult to really develop economic responses when you're in the programmatic mode. So I'm really pleased to hear that.

When do you expect to have the office up and running?

MR. GLAZER: We are actually in the process--and this will be sort of a paid announcement if everybody is watching on TV--but we're in the process of staffing and looking for people to staff that office. So we want to get that very quickly. It is a top priority.

COMMISSIONER BROWNELL: I know we're going to hear from some of the customers, so maybe this question will get answered. But have you surveyed the market participants to see if the programs this summer actually achieved the goals? Did they work from their perspective?

MR. GLAZER: One of the things built into the program was to undertake those surveys. And so that is part of the plan. So we've had a lot of informal discussion, but we are going to as part of the plan. And Joe has actually been tasked by the Commission to do a comprehensive report on the program. We're still actually getting the final billing data in for the summer at this point.

Anecdotally, we've heard different things. We've heard people liking the flexibility of the program. On the other hand, people say, well, you know, some people say, well, it's not my business to be in demand response. You know, it's difficult to sort of, depending on the size of the business, and I know you're aware of this, it's difficult to get people focused on that. But we're intending to take a full comprehensive survey and not just anecdotal.

COMMISSIONER BROWNELL: Thanks.

MR. MILLER: If I may, I wanted to ask one question that actually had to do with this past summer. And it's not the question you and I had discussed earlier. It had more to do with I think it was July 5th this year -- the 3rd. There were considerable problems, a lot of demand. We went immediately into emergency conditions where there were block imports.

There was a concern raised, and I wanted to know whether or not this is correct, that there seemed to be a move towards the block imports before demand response programs had a chance to have any effect.

Could you sort of characterize whether that's correct or not or what the situation was?

MR. BOWRING: Just so I'm clear, block imports?

MR. MILLER: Yeah. The imports that were brought in that couldn't set the clearing price.

MR. BOWRING: Again, I'm not -- so you're suggesting that imports were permitted in before DSM was implemented?

MR. MILLER: That's what had been characterized to us.

MR. BOWRING: I hadn't heard it put exactly that way. But, I mean, the point with PJM, obviously, is that we're an open market. We don't either restrict or encourage imports. Imports react to the price.

So if I'm understanding your question properly, as LMPs rise in PJM and participants on the outside expect prices to go further, and on an opportunistic basis in real time they decide to bring energy into the market -- and that's something obviously we encourage, we make possible. That's not something we make an explicit decision to do.

At the same time, when the dispatchers, the controllers of the system are looking forward, they thought we were going to be in an emergency situation, and as a result called on ALM and called on the emergency DSM program.

One of the points made about that is that in fact when the load actually came in, it came in somewhat lower than had been anticipated. Looking back with perfect hindsight, the dispatchers should not have called on. But dispatchers don't have the luxury of operating with hindsight.

Is that responsive to your question?

MS. DILLARD: Good morning, Chairman Wood and Commissioner Brownell. My name is Janice Dillard, and I'm the regulatory policy administrator for the Delaware Public Service Commission.

In addition to the direct energy cost benefits and environmental benefits that can come from DSM, Delaware believes that DSM can also provide relief in the area of transmission congestion. Delaware is part of the Delmarva

Peninsula, which is a load pocket.

And since mid-year 1999, the Delmarva Peninsula has suffered severe and persistent congestion of their transmission facilities serving the peninsula. And this has resulted in higher and less predictable costs to serve load, and Staff believes this has impeded the development of retail competition in Delaware.

Small, highly concentrated load pockets are frequently encountered on the peninsula. In PJM's Market Monitoring Unit in their 2001 report on the market, using the Herfendahl-Hirschman Index, found concentration ratios ranging from 3,500 to 10,000 during periods of local constraints.

We have limited natural gas supply. We have environmental concerns in Delaware, and we have a fairly rural load. So it's caused Staff to look very seriously at other solutions such as demand-side management, along with more conventional solutions of additional generation and transmission upgrades.

I'd like to describe the programs that are currently in place in Delaware, and these are in addition to some of the things that are going on at PJM.

The Delaware Electric Cooperative has 16,000 switches to control, air conditioning and water heaters -- and that's out of an eligible customer base of 50,000. The co-op can also control distributed generation for several hundred customers in the areas of irrigation, larger commercial and poultry farmers.

This summer the co-op was able to reduce its peak load by about 10 percent, and I understand its average load by about 7 percent, and that's of a 220 megawatt peak.

In 1999 when the Delmarva Peninsula was subject to rolling blackouts, the co-op was able to meet its load-shedding obligation entirely through its load-control programs.

Delmarva Power & Light, also known as Connective Power Delivery, currently has a peak management riders for large customers, which is a demand credit for allowing interruption, and an Energy for Tomorrow program for residential customers, which is air conditioning and water heating cycling.

The Energy for Tomorrow program is not actively being marketed by Delmarva Power & Light, and the credit offered to the larger customers on the peak management tariff was reduced significantly in 2000 after restructuring.

So the reduction from these programs this last year averaged from 40 to 120 megawatts, and I don't know how much on-peak. Delmarva is still working through the numbers. And that's a load on the peninsula of 3,000 megawatts. So you can see that the co-op was much more successful in percentage terms in being able to control their load.

And I believe that is because of the way their agreement with their power supplier is structured, they get a huge monetary benefit by reducing their load. It's not just an emergency program, but an ability to reduce -- to manage their power supply costs.

There are some initiatives that are being looked at right now and going into the future in Delaware, and one is the governor has an energy task force that's looking at issues that are -- a lot of energy issues, but some of the ones that are relevant to DSM and the issues here are clean distributed generation fueled by soy diesel instead of just, you know, dirty fuels, and a promotion of renewable resources and energy efficiency programs.

Also, the Delaware staff in conjunction with Delmarva Power & Light and other interested parties, is going to begin an advanced metering pilot program that will allow customers to see the price on a real-time basis and adjust their use accordingly. That's going to start as a small program for smaller customers, and we're very interested in that.

And we're also forming a working a group to identify cost-effective DSM or conservation programs.

In conclusion, again, DSM is one of the tools that we're looking at in Delaware to try to deal with a lot of issues, and we think it has a lot of potential. Thank you.

CHAIRMAN WOOD: Ms. Dillard, how does the retail programs that you just laid out here, how do those feather, to use Joe's word, with the wholesale programs that are being dealt with?

MS. DILLARD: Well, that was kind of an issue I know when PJM developed their programs is how these programs would interact, and I might leave it to Joe to answer that.

MR. BOWRING: I haven't heard of specific problems, but I think the fact that, for example, that some of these programs exist is testament to the reality that people are reacting to price signals. It's certainly the case there's been congestion on the Delmarva Peninsula. There have been higher prices there than elsewhere, and it's a market response, an expected market response, and a great one that customers have developed retail programs to, for example, interrupt load, as Janice indicated, to respond to those prices and to create an economic benefit.

Clearly, some of the programs she described are ALM programs, and those are part of the PJM program.

CHAIRMAN WOOD: Mr. Kleppinger, welcome back.

MR. KLEPPINGER: Good morning, Chairman Wood, Commissioner Brownell. On behalf of the 37 large commercial and industrial customers that form PJM Industrial Customer Coalition and their eight billion kilowatt hours of consumption per year, we appreciate the invitation to speak here today on load response programs.

Eight of PJM ICC members are formal PJM members who were able to participate in the program directly with an end-user interface directly with PJM. The remaining members of group who participated operated through a curtailment service provider.

According to Mr. Bowring's numbers of 320 megawatts in the economic program, more than a third of those megawatts, 126, were from PJM ICC members. Of the 510 megawatts that Mr. Bowring referenced in the emergency program, more than two-thirds of 352 megawatts are PJM ICC members.

These companies were active participants in the development of the programs during the stakeholder process that led to the filings at the Commission.

There are several positive influences that we feel came out of the program this summer. There was quick and easy registration. It certainly attracted more participation from nonactive load management customers than what had been there previously.

It certainly focused customers on day-ahead and real-time market prices that were occurring, even where those customers weren't subjected to those prices directly in their retail rates, along the lines of Mr. Glazer telling us that rate caps are not an inhibiting factor towards development.

We had several customers that actually tried to schedule plant shutdowns and maintenance in anticipation of high load periods. The participation in these programs helped facilitate that, and they did the right thing.

The e-data systems allowed for easy customer tracking of the market prices, and certainly the PJM staff has been extremely cooperative and responsive to end-user member inquiries in their program participation.

Unfortunately, this isn't quite enough because consistent with Commissioner Brownell's comments, this is a program. This is not a market. And it needs to become a market. And it needs certain enhancements and incentives before it can be truly a demand market that is capable of sufficiently offsetting the supply market.

I have listed a few recommended enhancements. Some of these were debated extensively during the stakeholder process and did not make their way into the program.

First, LMP-based contract customers cannot participate in the economic LRP program. We made some modification to that, and some of those are now capable of it, but pure LMP-priced customers cannot. That has the impact of excluding a substantial number of megawatts from potential participation.

Reference was made earlier to the generation and transmission offset where the LMP is priced below $75 a megawatt hour. In order to incentivize that participation, we believe that that generation and transmission offset should be eliminated. We hear references to the subsidy that could exist in this program, and we hear about the socialization of the costs of the program.

However, we pay very little attention to the socialization of the benefits that occur in the program. And I noted that in response to some of the questions from the Commission, one of them submitted by PJM indicated that on July 3rd, the effect of the program was to reduce market price by $60 per megawatt hour. And if you multiply that $60 per megawatt hour savings by the number of megawatt hours cleared in the market that day, the socialized benefit, if you will, is rather dramatic. And I think we tend to focus a little too quickly on the alleged subsidy or the socialized cost of programs without focusing on the benefit.

Chairman Wood previously questioned on the feathering, if you will, of retail tariffs, and in fact there are some issues there are some issues there. They don't fit particularly well into the PJM program where the retail tariff is an ALM-based program, which we always tend to characterize as a capacity or a reliability program, and not all retail tariffs throughout the PJM region will permit the customer to obtain the energy benefit associated with the ALM reduction.

There are capacity markets and there are energy markets. ALM is primarily a capacity-based market in which customers do not receive the energy payment. And if they would, it would be a further incentivization to participation.

I think a positive feature of the emergency program is that it permits special membership in PJM in order to qualify. We believe if that were expanded to the economic program, it would also facilitate customer participation and eliminate the use of a middleman or a curtailment service provider.

I think the individual PJM ICC members who are formal PJM members confirmed this summer that they do have the sophistication to operate directly with PJM, and that program could be expanded and eliminate the curtailment service provider. Because that's a middle step in the market where, frankly, some of the benefit that would flow to the customer has to be paid to the curtailment service provider.

Specification of the steps that are used during load reduction periods to assure that the maximum amount of voluntary load reduction occurs prior to mandatory load reduction programs like ALM, without any consideration of price. And I think Mr. Bowring made it clear that price is not a consideration in those circumstances. However, if there is voluntary load reduction capable of being extracted out of the market, it should occur before an ALM event is called, which is then a mandatory action.

If we could participate simultaneously in the emergency and economic load response programs, and then on a given day, if an emergency is called or if the customer is participating in economic, they would have the choice on that day. Currently, they're limited to select the program one at a time. They can change programs on certain days with notice, but it would be better if they could be registered for both programs and then select.

A few minor issues on market user interface. They're not major, but they would facilitate a little better participation. The customer baseline formula for calculating the amount of the load reduction has proven to be somewhat complex. We don't have the best answer yet on how to simplify that, but we will work with PJM to see if there is a better way to verify customer baseline.

The payment schedules have strung out a little bit, I think, partially due to distribution companies that aren't responding to the 10-day window for data submissions to get our payments. From the June economic participations, I think the payments just went out this week. So it would help if we could help speed that process.

And finally, and I think this is along the lines of Commissioner Brownell's question, these programs would sunset at the end of 2004. That's not much of a market if you're going to say it's only going to exist for two or three years. We think we should make it a market, and if it needs revisions between now and 2004, let's continue to make those revisions as we have the rest of the PJM market rules for the last six years when we've made close to 200 market rule revisions. And we still don't have that perfectly right, but we're getting there.

This will also need revision over time. But if it's believed to be a program by the end-user community and may not exist January 1, 2005, it's going to cause customers not to invest what's necessary to make the program a market.

Thank you. And, bless you, Mr. Chairman.

(Chairman Wood sneezed.)

(Laughter.)

COMMISSIONER BROWNELL: I think I'm hearing two different views, and I just want to get a clarification here. Joe, you said that the ISO should not get in the way of the curtailment service provider. And, Dave, you're saying that in fact that's an unnecessary step. Do I understand that kind of difference of opinion correctly?

And then let me just ask a second question, which is you mentioned that a number of these recommendations had been made during the stakeholder process and didn't make it to the kind of end program. What were the concerns? Who were the objections coming from the in stakeholder process so we can just get a better handle on where the barriers might potentially be?

MR. BOWRING: Well, speaking as one barrier, I actually participated in a meeting where I actually thought that the DSM program was going off the rails a little bit. That is, it was going too far towards overpaying for DSM and providing subsidies being spread across loads that weren't benefitting from it.

So, I mean, in part it was my position, although it was obviously other people's position as well that particularly when load is already seeing the benefit, for example, the G&T piece of the retail rate, if you don't consume, you see that benefit immediately, it doesn't make sense to pay that again, particularly when the price is below $75.

One of the original proposals was, as David is proposing again now, that there not be a limited for $75. The reason it was introduced was as a compromise, to recognize the fact that there are greater benefits above the elbow in the supply curve, and below that, it doesn't make sense to in fact subsidize load for getting off at that point.

And to go to your first question, if I understood it correctly, the problem with saying that you need to do voluntary first and then mandatory is that that's just not the way it works in real time. The dispatchers are responsibility for reliability, as Dave had said. They're not worried about price. They're worried about reliability. There's a two-hour lag for a significant amount of LMP resources. They simply -- if they want to be reliable, if they don't want to be shedding load, they have to call on that ahead of time. And there's really no way to avoid that.

The intent is not to interfere with the voluntary. But in practice sometimes, there is an interaction.

MR. GLAZER: Commissioner, if I could just follow up on this whole issue of the role of the curtailment service provider, there really is a policy question here going to what is the role of the ISO relative to the customers, specifically the retail customers?

Traditionally, you think about these programs. They were offered by the vertically integrated utility to its customers. That clearly was not -- and they were split-the-savings type programs. So the LMP was there, but the customer was not seeing that full benefit, because there was a split-the-savings with the local utility.

Our basic philosophy was, let's get competition in the provision of these programs so that the utility is not the sole provider of demand response, but in fact we've got lots of curtailment service providers that are providing innovative programs.

When you have too much -- there needs to certainly be interaction with the ISO, but when the ISO is the sole provider, in a way you almost create a new monopoly in effect, if the ISO has the only program and the curtailment service providers can't play in, I think there's a downside to that as well.

So it really is a policy question here. And I think that was some of the thinking that went into this in the discussions.

MR. KLEPPINGER: A couple of comments. On the curtailment service provider issue, I'm not recommending that it necessarily be eliminated, other than that a customer, should they choose, be able to work directly with PJM as is done in the emergency program through the special membership status, and as is done in the economic program if the customer is a PJM member.

With me today is Larry Steleka from BOC Gases. His company is a PJM member. So he participated in the economic and emergency programs directly. He did not use a curtailment service provider. He could have elected to if he desired, but he had the choice, and he did it himself. And I think all customers should have that choice through the special membership status.

We've debated a lot of these issues within the stakeholder process, and it's rather entertaining to try to debate Mr. Bowring on economics. But I try to get to the practicality. And the practicality is, we had a market this summer with 320 megawatts of economic program participation on a peak load when we were hitting all-time peaks of 64,000 megawatts.

That's not a particularly good balance between the demand side and the supply side when you look at the total size of this market. All I can take from that is that the demand side needs help to learn how to participate in the market. That help may be in the form of what people are calling subsidies, and may be necessary in the short term.

I would still posit it's not necessarily a subsidy if you look at the entire socialized benefit.

Secondly, in trying to answer Commissioner Brownell's question on where the barriers were, I think it's pretty clear if we would go back to the PJM membership meetings when these programs were voted on, how the votes tended to split. They pretty much split with the end-use customers, potential curtailment service providers and load-serving entities that are typically short as opposed to long, being on the side of encouraging program participation and perhaps being more aggressive in some of the terms and conditions of the program.

On the other side of the equation, the generators, the load-serving entities that perhaps are consistently long, and most transmission owners were on other side. And if you look at the votes, depending on which issue within the program, our votes at that time were going 2.0 to 2.0 on a sector-voted basis.

So it pretty much was a split down the middle I think on the two programs that were actually presented to the membership for a vote. And then the board, as it should do, took the independent stance and said the membership doesn't have a majority here. We're going to file a program. And they did. And it's better to have one in place than none, certainly. But it also shouldn't be stagnant.

MR. URBIN: Greg Urbin, Baltimore Gas & Electric. And I am a curtailment service provider. Just to, if I may, before I start my presentation, just to comment on what Dave was just saying, I believe this was the first summer that we had a program.

The numbers might not be as large as we would like, but we have to remember if we go back, the program was approved by FERC -- no fault of your own -- late in the spring or right before the summer. So it was difficult for a lot of us to get out and promote this program, not knowing what really was going to happen.

So I think as time goes on and we're allowed to get out there and educate the customers, we'll see these numbers rise. And that's just to follow-up on the comments that we had earlier.

COMMISSIONER BROWNELL: So that if we had an earlier filing from PJM and could approve it earlier, like April, May, March?

MR. URBIN: Again, we're not here to point fingers and I don't want you to get that impression.

COMMISSIONER BROWNELL: No, no. I'm just trying to get a feeling of what kind of timing you need.

MR. URBIN: The earlier we have these programs in front of us. During the winter, January through May is the time where you'd want to be out promoting these programs.

People are starting to see the forward prices in the energy market,a nd it's much more easier to get these programs out, to explain them to the people, the rules being set at that time, and then you can get people's participation.

But it was late last year before we did get the programs rolled out.

I am a curtailment service provider and I'm here basically today to talk about how well the program worked for us this summer. BGE was actively involved in the development of the load response program. We had attendance in every one of the meetings.

(Slide.)

My first slide just shows you a summary or status of our 2002 load response resources. The upper five I have listed as tariff-based resources, and that's because that's how the customer gets paid. Those are filed with the Maryland Public Service Commission, and the customer would get paid based on published rates. And those fall into the PJM active load management program that Joe had mentioned earlier.

The market-based resources our Rider 24, again, and our Energy Information Management, are filed with our Commission. But the payment to the customer is market-based. We use the PJM economic load response program to sign up customers and allow them to participate and pay them using the economic load response program from PJM.

Briefly, our Rider 24 has two options. The option one is the PJM economic load response program. It has the real time market and the day-ahead market. All of our customers that signed up this year were in the real-time market. I couldn't get anybody signed up for the day-ahead market.

We'll spend the winter finding out where the problems are, education again being a big part of that. It gets a little bit complicated when you start talking about the day-ahead and if you get selected, and the higher of the day-ahead price or the going, you know, the LMP for the hour. So we need to get out there and educate our customers a little bit more.

What's great about these programs, and the customers love it, is the participation is voluntary. You're not getting a call at eleven o'clock to curtail load in two hours and disrupt a full day's production. They get to decide when they want to participate in the program, what's best for them. They know their products. They know when they can curtail.

So under our Rider 24, they simply e-mail me when they're going to start their curtailment, when they're going to end their curtailment, and I supply that information up to PJM and they're registered for that day.

Again, the participants make the decisions regarding when the reductions occur. All we ask is for a half hour notification.

Rider 24 also has an option two. This is not part of the PJM program, but we offered a firm demand reduction option where a customer would curtail load during PJM's step two, and we would pay them a fixed capacity payment for whatever contract they wanted, be it one month, two month, summer period, a year.

We would take a look -- what's different about this program is we base the payments on the future value of the capacity. We looked at, okay, you want a contract for July. I looked at what the prices would be for capacity in July, and I offered them 80 percent of that value.

And again, the customer may participate in either of these programs, option one or two, or both.

What we're getting excited about is our Energy Information Management. It's an Internet-based tool, as I said, and in Rider 24, it's done by e-mail. There's a lot of drawbacks to that program. The customer that's participating in that program has to watch the PJM Web site to see where prices are before he curtails, and you hear, hey, I'm in the business of making widgets. I can't be sitting in front of the computer all day long. So we developed Energy Information Management to try to eliminate the problems that we saw by doing it by e-mail.

Another drawback to the e-mail version is the customer doesn't see his profile. Under EIM, although we are participating under the PJM program, we submitted an alternate customer baseline. Our baseline, we are able to calculate it the day before so the customer actually sees his baseline as he's curtailing during the day, and as his load drops, there's a graph that shows his load dropping down below his baseline, and his savings is calculated between his baseline and his actual load drop.

So when I go out to sell EIM, I'm telling them that it's giving you all the bells and whistles to optimize your load curtailment. Along with EIM, you get the paging and notification. They can receive a page when prices hit their set points.

So if they have a set point that they're going to turn off their equipment at $200, they'll get a page that the price has just hit $200. So if they're in a meeting, they can get up, go start their generator. If the price drops down below $200 in an hour, they get the beep. They turn their generator off. So it helps them optimize the use of their equipment.

Along with EIM there's the energy or near real time energy values. We post their loads every 15 minutes so they're seeing where their loads are and how they're dropping. And they also get 13 months of historical data using this product. This is a power Web-based technology.

Again, I already mentioned that they get notification of pricing and the alarming functions. And we believe that it facilitates participation in the options of BGE Rider 24, which is the e-mail version, or any similar non-BGE program. We would sell this product to a customer even if we weren't the curtailment service provider, and they could use the real-time data, the alarming and paging if they wanted to participate in somebody else's program. So we're open to that option also.

The PJM load response market attributes: PJM acting as the facilitator for load response programs. The greatest benefit or one of the greatest benefits is that PJM performs all the financial settlements and applies the credits and charges on a PJM monthly bill.

You can imagine if a third-part supplier and I want to go to his load and sign him up for a load-reduction program, I would -- we've talked about This. What would be required? Would I have to get a bilateral contract with this third-party supplier? And, oh, by the way, in order to participate, I need to know the retail rate that you're charging that customer. I doubt that I would get that information.

Under the PJM umbrella, all that's taken care of. It makes it so simple to go to a customer, say, will you sign up or would you like to sign up with us? And all that's taken care of by PJM. It eliminates all of those problems.

PJM also provides the web page where it has all the detailed information on the load response market. Customers can go out there and get educated, look at the web pages. We encourage that, for them to go and read up on the programs.

And PJM provides a list of registered curtailment service providers where you can go, where the load can go and say, here's nine, ten curtailment service providers; who would I like to call, and come out and talk to me about participating in the program.

It's very simple. The notification and the reporting to PJM is very simple. It's simply an e-mail that you send up to them. Later on in the season, we get a template where we fill out the loads that we saw during the curtailments, and PJM again does all the accounting and charging and the credits to the different PJM bills.

The PJM economic and emergency load response resources are market-based. We like that; we don't -- you want it to be market-based; you don't want it to relying on tariff-based prices that from time to time go in and out of the markets. The customer is getting paid what he sees on the real-time market.

And the PJM load response structure provides standardization across the market. Even if I go into a customer and I know that someone else, another curtailment service provider has been in talking to him about the load response programs, I know we're talking on the same wavelength, and the only real change could be how much he gets paid, the percentage that we're going to share with him, so that helps out.

PJM load response program drawbacks: The market subsidies contained in both the economic and emergency structures, we don't feel that that is appropriate. The special membership provision allowing PJM to transact directly with the retail customers, again, we don't find that appropriate.

And the market is constrained by the lack of metering and telemetry infrastructure for the small- to medium-sized customer. It's very difficult to get out there and get these small- and medium-sized customers involved in these programs when we require the hourly integrated data, so we need meters changed out and we need communications back to the LSE, or the curtailment service provider, and that adds a lot of costs to the program.

Future demand response markets: The appropriate design is critical, and that gets back to what I was earlier saying. We need the rules up front to go out and promote these programs, and to have programs that are constantly changing makes it difficult.

A lot of the customers that you're dealing with, you confuse them or we confuse them when we do make changes and we're not real clear on how the program is going to work. So we feel it's appropriate to take the time to get the program almost right before we get out there and have to make changes from year to year.

Market participation of the generation of the load response resources must be designed so that they can compete on a level playing field; that's imperative. We need the generators and the load getting the same rules applied to them.

And we need comparable resource verification. The load should be required to prove that they responded just as a generator does.

And, again, no subsidies; equal value for equal resource, and, again, thank you for your time.

CHAIRMAN WOOD: Great, than you, Greg.

COMMISSIONER BROWNELL: I just have to quick questions, and I know we're under a time constraint. Metering is a story for another day, because I'm very confused about where the costs are and what the real costs are.

On the other hand, I think that in PJM, at least some of the members, as part of a routine change-up in metering, have, in fact, the capacity to deliver real-time information today; is that correct? Can you tell me, Joe, at some point, not this minute, what percentage -- what companies have that, and what companies have in the works, plans to introduce updated metering?

Mr. Urbin, do you own the -- is the software that you're providing for the notification and the web-based software, is that proprietary?

MR. URBIN: Yes.

COMMISSIONER BROWNELL: You developed it inhouse, or bought it?

MR. URBIN: The Power Web developed it for.

COMMISSIONER BROWNELL: Power Web developed it. And are they selling it elsewhere in the market, or do you have -- they are? Okay, how many members of PJM have bought that or something similar, do you know? Maybe Power Web would let us know. Thanks.

CHAIRMAN WOOD: Great, thank you all very much. We'll move on to the next panel.

SECRETARY SALAS: We will continue our discussion of Item A-3, Demand Response Programs, with the second panel, New York ISO participants David Lawrence, James Gallagher, Steven Fernands, and Robert Loughney.

And Mr. Lawrence will begin the presentation. Good morning.

MR. LAWRENCE: Good morning. Thanks for the opportunity to have us talk to you briefly about the New York ISO demand response programs and the participation and performance that we've had in 2002.

What I would like to do is briefly go through the three programs that we offer in New York, both economic- and reliability-based.

I will present to you very briefly the performance in both of these programs and then talk to you about where we are going with these in the future, and also looking at some other avenues that we can look at for demand response.

We have two programs that deal primarily with reliability-based issues that are situations where operations, either in terms of reduced operating reserves or major emergencies would require that we can call upon demand-response participants.

The first program is our Emergency Demand Response Program, which we have opened up to not only the load-serving entities, the commodity providers, but also to aggregators. These would be business entities that have been established to provide an interface between the ISO and the end-use customers.

The program pays for energy reduction. We have a payment structure that's similar to the one that you've heard from PJM. We pay out the greater of $500 per megawatt hour or the marginal price.

We have a degree of certainty in terms of the duration. We will promise to pay people for a four-hour performance. Obviously whatever they do is, the actual payment that they get is based on what their actual load reduction is.

Again, we use the normal hourly interval metering that we require as part of the program to get this information, and we have a customer baseline calculation which gives us an estimate of what they would have done had they not interrupted their load.

As of this year in September, we had a total of over 1450 megawatts that are registered in this program. Roughly 250 megawatts of that are onsite, behind-the-fence generation. The rest of it being interruptible load.

The second program that we have that we would classify as an emergency program is our ICAP Special Case Resources Program. This program, in contrast to the emergency program, which pays for energy reduction, the ICAP program provides a capacity payment, an option payment under essentially the same rules as suppliers of ICAP in the New York market.

The difference here is that generation providers in New York who are ICAP providers are required to bid into the day-ahead market on a daily basis, whereas the special case resources providers don't have to bid in. They have to respond, though, when we give them day-ahead notice, and for an event where we would need them, and two hours' notice in-day that we would require their interruption.

This can be provided through bilateral contracts or through our ISO administered auctions that we have. We have about 550 megawatts that's registered in that program. And people can participate in both the emergency program and the special case resources program.

Switching gears a bit, the other program that we want to talk about is our economic program, our day-ahead demand response program. This we feel is really the most important program in the sense that it allows demand response providers to participate in the day-ahead energy market.

What we have tried to do here is set this up so that demand-response providers are on a parallel with generation providers. That is, they can bid in just as a generator. They can bid in their desire to reduce load. They can provide these bids with exactly the same kind of parameters that a generator would do -- namely, they're allowed to put in three-part bids.

These bids are looked at within our security constrained unit commitment program on an identical basis with generation. In other words, if it turns out that over the 24-period that we're scheduling that they are economic, then they will be scheduled. They will have a locked-in financial commitment day-ahead, which says that they will be allowed to reduce load.

They can bid this in for multiple hours so that they can adjust this to their natural industrial process or commercial process.

The payments that we have under this program involve really three aspects. The provider of the commodity, the load-serving entity, will bid in the actual load as part of their normal load bid. The demand-response provider will submit a bid as a supplier to reduce that load. If that bid is accepted, a couple of things happen. First of all, the load-serving entity, who has bid in that load, will have his day-ahead load charge forgiven for that mount of load. And so if he's bid in five megawatts for this demand-response provider and the bid is accepted, then he'll have five megawatts taken off of his commitment in day-ahead.

On top of that, the demand-response provider, when he actually performs in day and does his load reduction, will be paid at the day-ahead price for the megawatt hours that he's actually produced in his load reduction. If he doesn't meet his obligation day-ahead, the difference between what he actually provided and what the schedule was is penalized at a 10 percent rate of the greater of the day-ahead price or the real-time price. So it's a fairly complicated equation, but you kind of get the sense of where we're going there on that one.

This obviously results in payouts that some have called the subsidies. We have worked very hard with the market participants and looked at the kind of people who can participate in these programs. We've looked at the behavior of those organizations, and a lot of what we see in terms of demand reduction is really not reduction, it's more shifting of load from one period to another.

It's the ability to be able to alter the times at which they conduct their processes as opposed to actually not building something. And that I think has driven the need we see for incentives. That, also and the fact that there's a very strong influence of retail rates that are set up that are not necessarily encouraging people to reduce load on their own.

Briefly, let me talk about the performance of the programs in 2002. I mentioned that we have about 1,480 megawatts. Twenty megawatts of that is actually residential programs that we have. We have a couple of residential programs, and direct load control that are participating on sort of a pilot basis, that aren't necessarily following all of the rules that we have, but we're looking at them and treating them as sort of separate entities in this program.

We called these four emergency events this year, two in April. The 17th and 18th were rather nasty days for the operations staff. We had extremely high temperatures.

We had a lot of transmission generation on maintenance, and we got into some fairly severe reserves problems, that we were able to call on these emergency programs. You can imagine that with no notice and being early in the season, a lot of people were not ready to perform. We did get 60 megawatts of response, and we did only call in the Southeast New York area. So it was a limited call that was made. But we did get 60 megawatts of response from participants then.

The larger events were on July 30th and August 14th, and we're still processing that data, the metered data that's come in. We should have that done by the end of the month. But we have very good estimates of what we think we got. We believe we got somewhere between 900 and 1,000 megawatts on each one of those days. It was very noticeable. Our operations staff was extremely pleased with the kind of response we got. And it did make a substantial contribution to maintaining the system reliability on those days.

In our day-ahead program, we have about 350 megawatts registered. We have I would say considerably less than that who are actively participating in bidding. In the supporting materials that we sent you, we had some graphs that show the kind of participation that we've seen over the last couple of years. Participation in 2002, both in terms of offers and accepted offers, was somewhat lower than 2001.

We are doing an extensive evaluation of these programs, and this is particularly an area that we're interested in.

I think one of the things that we'll find out is that prices in New York during this period were low enough that it did not encourage a lot of participation in this program. There really wasn't a great deal of participation at that point.

Finally, in terms of future program changes, one of the big issues that we faced recently is in our emergency programs, the sort of disparity between the payouts that we make in the emergency program, namely, the $500 level versus the kind of real-time prices that we're seeing in New York.

And it's a fairly I would say general observation that there was a lack of scarcity pricing in the New York supplier market, because on many of these days when we were up at our historically peak levels, we were seeing real-time prices in the $50 to $70 to $100 range.

This we felt was something that needed to be addressed. And one of the areas that the market participants have looked at is the area of allowing these emergency resources to set price when they are called. So what we have done is essentially restructured the program somewhat. We're calling on these special case resources first. They will also be allowed to set price. They'll also be allowed to bid in a strike price. And this bid-in price is something that would be done on an occasional basis. It wouldn't be done on a daily basis. And it would allow an mechanism to choose a reduced set of megawatts that we would call upon that would more effectively meet the resource needs when we have an emergency.

The emergency program registrants would be able to participate after special case resources if they are needed. They would still be paid the $500, and they would also be allowed to set price.

Our estimate is that from this year's programs that we've called them for roughly 22 hours this year. They would not be setting price in all 22 hours. From our calculations, they're really only needed about half that time if you look at the five-minute by five-minute real-time conditions on the system.

So we estimate that we would having these programs set LBMP maybe 10, 12 hours a year. And of those, probably ten of those would be set by special case resources with maybe a couple of hours with the emergency.

In the day-ahead program, we are working to allow third-party providers to bid demand reduction in the marketplace. This would allow for aggregators to participate in the day-ahead market. The principal areas that are impacted here are in our settlements process and also in making sure that the creditworthiness requirements for these participants are in place and are being observed.

Finally, we are undertaking a revamping of our real-time scheduling software, both in commitment and scheduling. And we're building as part of that the ability for demand-response to participate in the energy markets and in the reserves markets. These will quite likely involve the need for real-time metering for these participants, and we see that as being something that will be in place probably quarter one of 2004.

The last thing I wanted to do is just let you know that a couple of days ago we did, as a result of the market participants, we did get an award from the Peak Load Management Alliance as being the 2002 Demand-Response Achievement Award for Independent System Operators. And that was really through a lot of the hard work of the folks who are up here at the table with me.

CHAIRMAN WOOD: Thank you. If we can move on. Thank you.

MR. FERNANDS: Stephen Fernands, Customized Energy Solutions. I'd like to thank the Commission for inviting me to speak. I have worked with the New York ISO staff as well as the PJM staff since we've start3ed working on these demand-response programs. I've worked in particular with curtailment service providers, competitive load-serving entities, environmental groups and others that desire to see demand-response move forward in these markets.

I will be answering sort of four questions today. One is, why is demand-response important in the wholesale market, not just the retial markets? Why the current markets are insufficient, and why we need markets like the New York ISOs and for it to be a full market, not just a program, why this challenge is with the states, and then also what FERC can do, again, looking at the New York ISO program.

I'll skip over about our company and go into the importance of demand-response. As the Commission has stated many times, most recently in the SMD, demand-response plays an integral component into the market. It improves reliability. It relieves market power concerns, creates effective proxy for scarcity pricing, and also reduces the price for the remainder of the system, what my colleague David Kleppinger talked about as the societal benefit.

(Slide.)

A simple graph, and I didn't try getting too complex here. But just when you move from an inelastic to an elastic demand curve, the effects on price can be very dramatic, especially given the hockey stick shape of the supply curve that exists in the New York ISO as well as PJM markets.

It improves reliability in that it's much more likely that the two curves will cross, and also that during peak periods, generators will have to compete essentially with load in order to be the marginal unit. That generator may in fact not be taken even during a peak period because there's actually load that curtails instead of paying a high price.

Now why can't we just put the price out on the Internet, as some suggested? Put lots of interval metering on somehow, and throw the price out and people will just respond. And the whole thing will just take care of itself, and we'll all go home.

The existing markets have many limitations. The day-ahead and real-time prices don't end up being passed along to the end-use customer for many reasons. The first is, we talked about before, the vast majority of customers are on fixed prices or some type of negotiated prices.

There are operational limitations. People often can't send a group of workers home for a one-hour interval. They have to shut down their processes or switch their processes to operate at a later time period. And again, need advance notification, like many of our generators operating in the New York ISO need advance notification when they need a run.

Many customers don't have integral metering. This is an issue that's going to come up again and again, and something that ISO New England and others have tried to address. And I think sending the right price signals is the first way that you do that.

And then the last one is revenue sharing without curtailment service providers. When this used to be just about utility-sharing revenues, an interesting story just with the New York ISO. I know we're time limited, so I won't go into all of it. But where they used to have a revenue-sharing, where the utility would generously give half of the benefit of the curtailment to the customer, and just take half for themselves. It was 50-50. That sounds sort of fair, doesn't it. Except the customer was doing all the work, and it was actually switching the process.

Since we've migrated to this competitive market, the revenue split has been more along the lines of 10 percent going to the curtailment service provider, and 90 percent of benefit going to the end-use customer.

We also have things such as price cap load bidding and virtual bidding in the New York ISO market. These are very important elements in terms of providing price disclosure, allowing LSCs to hedge, and making customers aware of what their real-time exposure could be, and also it could be adjusted to allow for three-part bidding, although it doesn't currently.

But they are limited even with the virtual bidding or the price cap load bidding. First of all, if a customer is with a vertically integrated utility that has a lot of generation, as is more the case in PJM than it is in the New York ISO where they have largely divested -- but if it's a semi-vertically integrated utility, there may not be a price incentive or a market incentive to try to lower prices during peak days. They're going to maybe in fact increase prices during peak days, and that's where their business may benefit the most from.

So again, there may be benefits of allowing competition, and virtual bidding can only be done through a customer's load-serving entity.

The load-serving entity supply contracts. Many of the companies in the New York ISO have load-following contracts, which means that they've shifted the risk they have of these peak prices to some other party that's supplying those contracts.

So again they don't have the price signals, even the load-serving entity, to try to get customers to respond during those peak periods. And generally the party that backs the contract, a generation owner, doesn't have the type of infrastructure to contact individual customers to get them to respond. And also, there were operational limitations that didn't allow the operations constraints to be in the bids in virtual bidding, and a lack of competition.

So if we say, okay, this is really important, okay, the existing markets aren't fully going to solve it, then, some argue, we should just let the states do it, and so the states will handle it, and I believe the states do play a very critical role in this.

However, the states also have various limitations which, working in partnership with the ISO and the wholesale markets, they can overcome, but in and of themselves, may have found insurmountable or very difficult to overcome.

One of those is the customers that are currently served under capped retail rates, are worked out under complex restructuring agreements, and it may be difficult to give another tariff rate that customers would actually want to switch off of their existing rate onto that new rate.

If you start an ISO market, then you can try to come up with a new rate or something that can take advantage of the ISO market. But if you don't do an ISO market, it's difficult to come up with that new tariff rate. I think a lot of people have implemented real-time rates as part of their utility and had very few people migrate onto real time price rates.

Each utility's rates are unique, so even within an individual state, it's difficult to standardize markets a lot of the times, and that's one of the challenges that individual states have, as many of the Commissioners here are aware.

Each state has a different level of retail competition. So as far as curtailment service providers and allowing for competition among demand response, different states are at different points among that, and have different abilities to actually implement that.

And also states that are part of multi-state ISOs, which the New York ISO likely will be migrating to, and PJM is many, many states, would have a significant challenge apart from an ISO-centralized market to try to coordinate the demand response markets across states.

There's a real value to that from the perspective of my clients, the curtailment service providers and load-serving entities, in coming up with a standard design, because that helps in your marketing, that helps in reducing all types of lower overheads, implementing some of the Power Web and other technologies, and not modifying those.

New York ISO saw this. They saw that states couldn't do it alone. They saw that there was a need for it, and they moved and they installed many things that are very beneficial.

They allowed load to bid in the day-ahead, three-part bidding. They paid curtailed load full LMP when prices were at sufficiently high levels, and they had standardized baselines, both process loads and, later, weather-sensitive loads.

They allowed for demand-response providers, be it in emergency programs, as well as in the economic programs, as initially envisioned. Unfortunately, there have been technological problems with curtailment service providers in the New York ISO in implementing the software.

This is part of the larger problem with software that is being addressed, but is a continual challenge in trying to do what we want to do and what the members approve.

There are many benefits that the New York ISO has gotten from this: One is price transparency. They now know what customers are willing to accept to curtail or change load.

That's something they didn't know before. They just knew the prices went high and load increased, and the system went on. So, it creates a price transparency.

The second is the ability to impact prices. It's been stated before that the demand response has lowered prices, creating significant societal benefits, and the ISO is able to anticipate the DSR impact on reliability, and be able to use that in order to improve reliability.

Demand response, moving forward, we need to move, as has been stated many times, with programs to markets. We need to standardize elements across regions, such as the full paying of LMP that is in New York and isn't in other areas, including better access for smaller customers. And this is some pilot programs going on in New York ISO, a 25-megawatt pilot program, and also in PJM's recently-filed one.

And we need to increase those again from programs to markets, and allow smaller customers, through aggregation, to participate in the markets.

We need a better defined op ring surrounding emergency DSR programs. Dave just talked about this in terms of how do those get called on and how do they set price?

And then also establish levels of DSR that would trigger a lessening of other market mitigation measures. This is an important last point that I will leave with.

There is a lot of opposition among the generation community to some of the socialized costs and other things for demand response. Part of that is because they believe that when we tell them, well, when this goes in, it will relieve the need for a lot of market mitigation. And they don't believe us.

They say, no, you're going to get this demand response, and we're still going to have all the same mitigation we've always had, even when we have demand response. So coming up with specific objectives as far as if you hit this level of demand response, and we really do see the demand responding this much, we then feel that we can eliminate these types of caps or these types of rules, is very important to trying to build consensus support around demand response.

Thank you very much, Commissioners.

CHAIRMAN WOOD: We're going to take a break right now because we do need to get some business transacted on our normal agenda. So if you all would just hang tight for a little bit, and I'll turn it over to the Secretary.

SECRETARY SALAS: Mr. Chairman and Commissioners, the following are the items that were struck from the agenda, since the issuance of the Sunshine Notice on October 2nd: E-10, E-11, E-20, E-26, E-37, E-41, E-43, E-45, G-11, H-4, and H-8.

The consent agenda for this morning is as follows: Electric: E-1, E-2, E-3, E-5, E-6, E-7, E-8, E-9, E-14, E-16, E-17, E-18, E-21, E-27, E-29, E-31, E-33, E-35, E-36, E-38, E-39, E-40, E-46, E-47, E-48, E-49, E-50, E-51, and E-52.

Gas: G-1, G-2, G-3, G-7, G-9, G-10, G-12, G-14, G-15, G-16, G-19, G-20, G-21, G-23, G-24, G-25.

Hydro: H-1, H-2, H-3, and H-6.

Certificates: C-1, C-3, C-4, C-5, C-6, and C-7.

The specific votes for some of these items are: E-8, Chairman Wood not participating; E-52, Commissioner Massey dissenting, in part; G-2, Chairman Wood concurring with a separate statement.

And Commissioner Breathitt votes first this morning.

COMMISSIONER BREATHITT: Did you call my concurrence on E-44, or are we calling that separately?

SECRETARY SALAS: We're calling that separately, Commissioner.

COMMISSIONER BREATHITT: Aye.

COMMISSIONER BROWNELL: Aye.

COMMISSIONER MASSEY: Aye, with my partial dissent noted.

CHAIRMAN WOOD: Aye, with my recusal and concurrence, as noted.

SECRETARY SALAS: Duly noted.

CHAIRMAN WOOD: Go ahead with the next item.

SECRETARY SALAS: The next item for discussion in the discussion agenda is E-32, Cleco Power, LLC, with a presentation by Sanjeev Jagtiani.

MR. JAGTIANI: Good morning, Mr. Chairman and Commissioners. E-32 is a Petition for Declaratory Order concerning the proposed CTRANS RTO by a group of transmission-owning utilities in the Southeast known as the

CTRANS Sponsors.

They propose that a third-party independent system administrator will operate the CTRANS RTO in the States of South Carolina, Georgia, Alabama, Mississippi, Louisiana, Arkansas, and parts of Florida and Texas.

The Independent System Administrator will control over $9 billion in transmission assets, $2 billion of which are cooperatively or publicly owned and the CTRANS RTO would be one of the largest in the country.

The CTRANS Sponsors request that the Commission issue a Declaratory Order, determining that, number one, the governance structure and business model of the proposed CTRANS RTO satisfies the criteria set forth in Order Number 2000; and,

Two, the process by which they will choose the ISA, the Independent System Administrator, also satisfies that criteria.

The draft Order finds that the CTRANS RTO governing structure, centered around an independent system administrator and supported by an independent market monitor, satisfies the independence standards set forth in Order No. 2000.

Further, the draft Order finds that the process used to select the system administrator is consistent with Order No. 2000, and will result in the selection of an administrator that will independently operate the proposed RTO.

The CTRANS Sponsors' petition also seeks to show that its draft protocols covering market design, operations, pricing, planning, and transmission expansion funding, will support their proposed governance structure and business model, and will work to satisfy the requirements of Order No. 2000.

To this end, the draft Order provides preliminary general guidance on certain issue which the CTRANS Sponsors have identified as critical to the voluntary participation of the sponsors, including the concept of participant funding in the transmission expansion funding protocol.

Staff notes that there appears to be general consensus in the Southeast, particularly with the affected state regulatory commissions to have participant funding for projects seeking the economic expansion of the system.

The draft Order allows the use of participant funding in CTRANS as part of a general framework for system expansion. The draft Order also commends the progress made to date in developing the CTRANS RTO.

Finally, due to the broad overlap of issues in the CTRANS proposal, and in the recently-issued Notice of Proposed Rulemaking on Standard Market Design, the draft Order clarifies the Commission's intent not to overturn decisions made in the docket -- made in this docket, following issuance of a final SMD rule. Thank you.

COMMISSIONER BREATHITT: Thank you very much Sanjeev and the rest of the team who developed this Order in answer to CTRANS' request for declaratory action. I am pleased to support the Order before us today, and thank everyone again for putting the Order together that sends and what I believe are some very positive signals to those entities that are expending great efforts in getting this RTO up and running.

This was a region of the country that had no RTO activity, and they have really started this from scratch. And today's Order sends this well along the way.

I see bright prospects for CTRANS and I applaud the work of the Sponsors in developing a unique answer to the question of how an RTO should be governed. The CTRANS ISA will be the first of its kind, in that it will be an independent entity charged with operating and managing the grid that will also profit from its effectively managing that grid.

So this is a little bit different model than we have seen in the development of other ISOs and RTOs. My understanding is that the ISA will most likely be a partnership, pairing together businesses with expertise in engineering and business management, with companies that have experience in management of grids overseas; is that what your impression is at this point?

MR. JAGTIANI: Yes, that's correct.

COMMISSIONER BREATHITT: Today's Order finds that CTRANS is on the right track with regard to governance, selection process for the ISA, their general business model, their market design, and many other elements.

Of particular interest to me is our finding that CTRANS's proposal of participant funding for transmission expansion is allowable as part of a general framework; is that also what you stated?

MR. JAGTIANI: Yes.

COMMISSIONER BREATHITT: We recognize that there is some more work to be done in understanding how participant funding needs to work in this part of the country, and so it does make sense that we ask for some more detail about the plan that CTRANS sponsors have put together.

And we are also committing to technical conferences with the sponsors, just as we did three weeks ago in RTO-West. We talked about doing specific technical conferences, and so those will occur along with the other stakeholders in the Southeast to work through these details before the Commission sees a 205 filing in the full RTO application. So, I am pleased to be voting for this Order.

COMMISSIONER BROWNELL: Thanks. I would echo Commissioner Breathitt's comments and just add a couple: I'm pleased that we have addressed an issue that I think has been hanging over some of our recent activities, and that is specifically to this case, in this situation.

We are making it clear that we do not intend at some later date, when the SMD NOPR is completed, the final rule is completed, to go back and revisit all of these decisions. I think that's important for the planning, and I think it speaks to what we committed to several weeks ago, which is that SMD and RTO activities will, in fact, proceed apace, and be informed by each other, so I hope that's a helpful clarification for people. I look forward to working further on the issue of participant funding.

I'm pleased that this recognizes the wishes of many of the stakeholders, particularly the state commissioners in the Southeast, but I feel the need to, in fact, through the technical conferences and other comments, to be very specific and very clear about exactly what those rules are going to look like, so that everyone can address their business plans accordingly.

I would just comment on something I've commented on before. That would be the stakeholder collaborative process improved after kind of a rough start, but I noted in the comments here that many of the intervenors still feel that that needs some work. So I would encourage the filing parties and the stakeholders to work on their relationship and communications, and as we develop in what I hope is a pace which gets jump-started by this order.

COMMISSIONER MASSEY: This order generally has my support. I have a couple of issues I'd like to raise. One major concern and one more minor concern. I think generally speaking, this is a reasonable proposal that moves in the right direction. They're using the locational marginal pricing approach to congestion management.

I think the ISA is an interesting idea that's unusual in some respects, but the way it's set up I think it's reasonable and should proceed.

I do have concerns about the language that seems to me to tie the Commission's hands. The language says, in other words, unless the Commission has specifically indicated in this order than an element of the RTO proposal is inconsistent with the SMD proposal or needs further work in light of the SMD proposal, we do not intend in the final SMD rule to revisit prior approvals or acceptances of RTO provisions because of possible inconsistencies with the details of the final rule.

A couple of points. First of all, I don't feel like I've had sufficient time to adequately consider the implications of this language. To me it seems like a pretty big shift in policy that we ought to give very serious and thoughtful consideration, Mr. Chairman. And at this point, I haven't had the time to give it that kind of consideration.

Until this language was proposed at the eleventh hour, I was not aware that the policy of the Commission would be that we would not revisit industry structure issues in the SMD final rule. And I had been assuming that all of the public utilities would end up having to comply with the final SMD rule with whatever exceptions we build into it, regional variations and so forth. But I did not know that we were headed toward approving these individual orders and then making the commitment that we don't intend to go back and revisit these issues.

That frankly strikes me as an unprecedented commitment that ties our hands unnecessarily. And at this point this morning, I'm not prepared to vote for that.

I do have a specific -- another specific issue to discuss, and that is the way the Stakeholder Advisory Committee -- that's the SAC, right? The way that functions. And as I understand it, the Stakeholder Advisory -- well, tell me how it is set up here. Explain it to me.

MR. JAGTIANI: Okay. There are ten groups, and each group has two members. Market participants such as a Southern, can be part of the IOU group within the Stakeholder Advisory Committee, and they can also fall into other groups within the Stakeholder Advisory Committee or their affiliates can fall into those groups.

COMMISSIONER MASSEY: How many possible groups could they fall into?

MR. JAGTIANI: I believe it may be in the case of Southern, I gave it some thought. I think it's three, off the top of my head, that they could fall into, such as the Transmission Developing Group, Generator Affiliate.

COMMISSIONER MASSEY: Now tell me what this Stakeholder Advisory Committee actually does.

MR. JAGTIANI: The SAC was involved in culling down the selection for the ISA, for the Independent System Administrator.

COMMISSIONER MASSEY: The SAC is the entity that makes the recommendation of the slate of ISA candidates?

MR. JAGTIANI: Exactly. There were nine candidates, and they culled it down to four candidates.

COMMISSIONER MASSEY: Which is really the guts of this proposal in terms of independence questions?

MR. JAGTIANI: Right. And going forward, they will provide advice to the ISA. And the other particular thing that they will be involved in is the selection of the Independent Market Monitor.

COMMISSIONER MASSEY: But a major utility might instead of just participating in one of the ten groups that forms the SAC, could actually participate in three? Maybe more than that.

MR. JAGTIANI: Yes. It and its affiliates could participate in let's say three.

COMMISSIONER MASSEY: Okay. Now the order handles this by saying we just want to note. It raises this issue that says we just want to note that in recent RTO governance structures acted on by this Commission, each market participant, including all of its affiliates, is only permitted to participate in a single stakeholder group.

So we point that out, but we don't tell them to go back to the drawing board?

MR. JAGTIANI: That's correct.

COMMISSIONER MASSEY: Okay. Mr. Chairman, my view is we should amend this Order to add to the end of paragraph 59 the following, as I read: Each market participant is only -- in recent RTO governance structures acted on by this Commission, each market participant, including all of its affiliates, is only permitted to participate in a single stakeholder group.

At that point, I would strike the period at the end of paragraph 59 and insert: And we find this arrangement to be more appropriate. Sponsor's proposal could allow certain market participants to have too much influence in SAC discussions. The proposal should be modified accordingly.

That is my proposal. I do have concern that a large market participant that has a number of affiliates that are in various businesses could have an undue influence on the deliberations of the SAC. And I would like to offer that to my colleagues for their consideration.

CHAIRMAN WOOD: I'm there. I had thought our language made that point, but if it needs to be more direct, then I would certainly think that the ability to kind of be the power behind the throne of ten thrones is not really a good outcome.

So if we're going to depend on the SAC for a big role in independence, I think that's a good idea. So if that language needs to be beefed up, I think that your approach would get us there.

COMMISSIONER BROWNELL: I'm okay with that, one, because I think we should be consistent to the extent that we can among regions. And two, for the reasons that Bill points out. I think it's very important for stakeholders playing an important role to have equal footing.

COMMISSIONER BREATHITT: I'm not sure we know whether anyone can participate in the stakeholder groups. Do you know? And others are open to anyone participating.

MR. JAGTIANI: I'm not sure that I understand your question.

COMMISSIONER BREATHITT: I think that answers it, that we don't know.

MR. GREENFIELD: Commissioner, if I may. The stakeholders groups, there are ten of them, and they are sort of defined groups. Each has a certain segment of the industry in it. So that to some degree by definition, you're going to be getting a certain segment within each of the stakeholder groups.

Now somebody like Southern, for example, overlaps into several, because they're involved as an investor-owned utility. They have power marketers, and they have generation. So they could fall into three groups and could participate in all three groups. But some of the other groups like consumer advocates and environmental interests, obviously they would not -- or at least my own take is that they wouldn't fall into that group.

So there is some limitation by definition because of the way groups are constituted.

COMMISSIONER BREATHITT: But I'm hanging my hat on the word "participate".

MR. RODGERS: Could I offer one clarification on this too? In terms of the ISA selection process, the transmission owners and CTRANs cannot vote in picking the slate of final candidates. So, in other words, the final four candidates that the SAC pared the initial nine down to, the transmission owners had no vote in that whatsoever.

COMMISSIONER BROWNELL: I'm not sure we're talking about that. And Bill's point is I think to kind of the future on the issues.

But let me also clarify as long as you bring that up, however, the transmission owners themselves will alone choose from that final slate of -- I thought it was down to two, but maybe it's four.

MR. RODGERS: It was initially put down to four, and then two of the four dropped out. So it is now down to two. And you're correct, the CTRAN sponsored, which are the transmission owners, will by themselves select from that group of two.

COMMISSIONER BREATHITT: I'm trying to ascertain to determine whether this language works for me if there is a distinction between voting and participation. And if we don't know the answer to that, then I need more time to consider Bill's amendment.

MR. GREENFIELD: I think the way it works, and Sanjeev, correct me if I'm wrong, but I believe the way it works is, is the stakeholder groups get together, each of the ten groups get together and identify two representatives to the SAC, the Stakeholder Advisory Committee. And so now you have ten groups, each with two representatives. And those 20 people I guess probably either physically or figuratively get together in a room, and those 20 people vote.

And of those 20 people, even though, for example, Southern arguably could participate in three groups, I believe they're only allowed to have one member among the 20. So you wouldn't have a scenario where Southern would have three of the 20, for example. They could only have one of the 20, albeit they're involved in all three of the groups, they only have one of the 20 members. So they're not -- Southern wouldn't have more than one vote, although it participates in three of the groups.

COMMISSIONER BREATHITT: So what is your amendment restricting, Bill?

COMMISSIONER MASSEY: Participation in the groups. You have to choose a group.

COMMISSIONER BREATHITT: Participation?

COMMISSIONER MASSEY: Mm-hmm. You have to choose what --

CHAIRMAN WOOD: And then the participants can vote on who represents that group, so that you get a vote at a level below the SAC.

COMMISSIONER MASSEY: You have to choose what group you're going to be involved with in the SAC.

COMMISSIONER BREATHITT: I think it is good to restrict voting. I don't think it's good to restrict participation. These processes should be open.

CHAIRMAN WOOD: It is the voting of the representative from that sector that you're concerned about?

COMMISSIONER MASSEY: I understand the voting process, but I'm concerned that a market participant that is involved in lots of different businesses can be involved in lots of different places and have an undue influence on the deliberations of this SAC.

COMMISSIONER BREATHITT: My question is, are we going to then be saying these meetings have to be closed and you can't participate? Versus vote.

COMMISSIONER MASSEY: It was my understanding in other orders we have tipped our hat fairly strongly toward saying you've got to choose.

COMMISSIONER BREATHITT: For voting purposes.

COMMISSIONER MASSEY: I don't think that's true.

COMMISSIONER BREATHITT: Okay.

COMMISSIONER MASSEY: But I could stand to be corrected, but I don't think that's true. We also in this order go halfway toward telling them that we're concerned about this, then we sort of leave it up in the air.

We say to them, we note that in recent RTO governance structures acted on by this Commission, each market participant, including all of its affiliates, is only permitted to participate in a single stakeholder group. And my own view is that should be the policy of this Commission. That's the point I'm making.

COMMISSIONER BREATHITT: I guess I need to understand the difference in "participate" and "voting" better before I can --

MR. RODGERS: Commissioner, I have one sentence here from the application that might shed some light on that. The application states that the participating owners and CTRAN sponsors will be involved in vetting potential candidates but will not participate in voting on those entities that comprise the SAC's slate of final candidates.

COMMISSIONER BREATHITT: So there is a distinction in the voting and the participating?

MR. RODGERS: Yes. I think they are trying --

COMMISSIONER BREATHITT: What I don't want to cut off is the participation. But I think it's fine to qualify and limit the voting. So we may need -- I don't know.

CHAIRMAN WOOD: I mean, I think the preface of this whole paragraph, and I guess to kind of address Bill's concern that we went halfway, actually we said the role of the SAC is just not clear at all as a preface to this. And oh, by the way, this stakeholder participation issue does not appear to be consistent with where we're going.

I think if we said when you come back on your 205 filing, you know, this needs to be consistent with where we are with RTO West and the other people.

COMMISSIONER MASSEY: Yes. My own view is the SAC is a very important group. It was important in choosing the slate of ISA candidates. And it's going to be extraordinarily important moving forward as well, and that it's not an insignificant matter how it's structured, both the voting rules and the participation rules, so that a market participant that happens to have a number of affiliates -- it might be structured so that several of them will go out and form affiliates so that they can participate in various groups.

And, I mean, I really don't see the point of that. I think you ought to choose what group you're going to be in and participate accordingly, so that you don't have an undue influence on even the deliberations.

CHAIRMAN WOOD: From the application, was it clear that the individual stakeholder groups had any function other than to pick their member for the SAC?

MR. JAGTIANI: If I may, the stakeholder advisory committee was also involved in participating in the development of the various protocols that CTRANS has submitted in a draft form right now.

I believe the team assumed that their involvement would continue, subsequently.

CHAIRMAN WOOD: That's the SAC, not the subgroups under the SAC, right?

MR. JAGTIANI: Right.

CHAIRMAN WOOD: Do the subgroups under the SAC that we're talking about now, a single stakeholder group, do they serve any function other than to elect their member for the SAC?

MR. JAGTIANI: They would provide advice, and any single stakeholder group could also still come in and provide advice to the ISA. That's the way it's worded in the application.

COMMISSIONER BROWNELL: Is it not our experience as the organization develops that stakeholder group's review, recommendation, such as demand-side management programs, and is not one of the issues of the multiple participation that depending on what the rules are, several stakeholder groups can delay or amend recommendations as they move forward, and isn't one of the issues, as it has evolved in various stakeholder processes, that it also becomes a resource issue that large organizations with multiple affiliates can often out-resource? Let's just say the consumer advocates or a state commission that might be -- I think that those are the kinds of issues that Commissioner Massey is trying to anticipate.

I don't want to speak for you, Bill, but --

COMMISSIONER MASSEY: No, I think you have articulated it well. I appreciate your clarification.

COMMISSIONER BREATHITT: My thought on this is to figure out a way to not limit people or entities having the ability to say what they want to say in these stakeholder committees.

If they have to be a member to be able to say what they want to say to participate --

MR. JAGTIANI: If I can just --

COMMISSIONER BREATHITT: -- that's what I feel we're trying -- that we're starting to restrict, the ability to be able to talk in those.

MR. JAGTIANI: If I can address that concern of yours, the CTRANS Sponsors' proposal states that the SAC meetings would be open, and, in fact, invites participation from the affected state commissions, as well as ours and any other interested stakeholder.

COMMISSIONER BREATHITT: So why would we limit participation?

COMMISSIONER MASSEY: We have we approved proposals that limit participation, and why does this Order -- if that's not our policy, why does this Order express a concern about it, and sort of point them in that direction without really insisting that they change it?

What is our policy? What are we trying to achieve? Do we care if market participants are on all sides of the market and participate in this influential group, in this influential committee in a number different groups?

It seems to me, by definition, that means that those who don't have affiliates and are just on, you know, one side of the market, are going to have less influence. That's my concern.

MR. GREENFIELD: I think there was a general -- and I'll be honest that I can't swear I have encyclopedic knowledge of all of the Orders that we've issued on this topic, but I -- my recollection of the general concern that underlay what we were doing in the Orders, was a concern that you would have one company or entity or one industry segment that would become an overpowering influence, and that the proposals that we have adopted to date where companies were restricted to one camp, if you will, or one group, however you want to describe it, that that was a response to the concern that we had; that is, we did not want people to have overpowering influence.

Presumptively -- and, again, I should say I'm reading a little bit into what Southern -- not Southern, but what CTRANS has done -- presumably the reason that they opted for the one audience reaction --

(Laughter.)

MR. GREENFIELD: What the hell; I'll make up something.

(Laughter.)

MR. GREENFIELD: I'm assuming that the reason that they opted for the one-vote-per-company rule was to address that concern. Now, whether something more needs to be done, of course, is a decision for you all to make.

MR. RODGERS: And if I could just piggyback on that comment, from the application, again, we're told that the participating owners will be allowed to participate in the SAC, but they will not have a majority vote on the SAC, nor will they have sufficient voting power to be able to veto a proposal.

So, I think they're intending to, you know, provide comments or engage in discussions within different committees within the SAC, but they are telling us that they are not going to have enough clout to be able, either as a majority, to block anything, or even to veto anything.

CHAIRMAN WOOD: Let me take a break here. While you all are sorting this out, let me invite Commissioner Dworkin to come up. He's on our panel. It is his anniversary today, and if I don't get him home to his wife, I'm in big trouble with half of the human race. So let me change subjects for a quick second, let the Staff research what the issue is here, and then invite Commissioner Dworkin to talk to us about the New England demand response program.

MR. DWORKIN: Thank you, Mr. Chairman. I appreciate your courtesy in trying to get back to the original schedule, and I know how challenging it can be, so I will try to be very quick.

I wanted to do a couple of things, though. I wanted to say a word of encouragement about how important the demand response and load response work is. I wanted to give just a sketch of a status report of where things are, and indicate a couple of what I'll call mid-level workman-like issues that people are addressing.

I wanted to express a real serious concern about one point, and I wanted to give a little bit of a hope or an anticipation about where things will go.

The first part, which is the encouragement about the importance of this is pretty straightforward. I sum it up in ways that I think are consistent with what the Commission has said, which is that a market without a demand response is like a bird with one wing; it just plain won't fly.

And the ways to get a demand response, ideally, of course, would be price-responsive load with an immediate feedback between the end-user and the decision about whether or not to commit a resource.

That doesn't exist now, and, in a meaningful sense, it's not going to exist for a predictable schedule, although we can all hope to move meters and some other things along, and we can hope that multi-settlement creates incentives in that direction.

It's not going to get the job done, and I think most of us recognize that it's a partial solution for a long time, and we don't know when it's going to be a full solution.

That means that load-response programs are needed, and unfortunately, the history on the load-response programs can be summed up in a lot of different words that all add up to disappointing, and it amounts to -- you can say that they haven't met the expectations, but far more important than not meeting the expectations, is, they haven't gotten the job done.

And the job is to make sure that hundreds of millions of Americans don't have to pay for the unnecessary running of expensive generating units when they wouldn't have been needed if somebody had had an option to take a pass on turning them on.

That's the task, and when we talk about achieving 20 megawatts or 22 megawatts or 30 megawatts, or even 300 out of a 25,000 megawatt system, we can see how trivial our success has been in getting there. So there's a lot that needs to be done on that score.

One thing for getting there, which Commissioner Brownell invited us to participate in, and which we really, with pleasure on behalf of the New England utilities made sense to go forward with, was to try to work together through something like the New England Demand-Response Initiative.

And I don't have time to walk through the details of it, but I want to say at a real high, fast pass, that it exists; it's meeting; it's meeting productively; it's getting a lot done. I have high hopes that it will produce something useful.

That's sort of like Lincoln said, with high hopes about the future and no promises are made. The fact is that the drafts of tariffs aren't done yet. There are still a lot of mid-level issues to be dealt with. Some of them fit into the kind of points that Craig Glazer made this morning. There needs to be an executive commitment to it.

I'll add one to his list of things, which is environmental. There are many parties to the New England Demand-Response Initiative Group and we think there are serious environmental issues raised by some of the load response proposals.

And while I think you have, in the PJM context, said any participant has to either have a permit or explain why they don't need one for their air emissions, frankly, many people think, and I'm on the edge of thinking, too, that in regard to your obligations under Environmental Impact Statements, the NEPA, you may need to be more open to looking at what the effects of what you do are when you change the existing world.

I think that on the entrepreneurial side, to pick up Craig's word -- I was going to call it marketing -- there's a real need to recognize that you can't act the way utilities did, which is to announce in May that a tariff is going into effect in June and people are going to live with it.

If you want folks to respond, you've got to get it out there. I know that Commissioner Brownell said March, April, and I think the answer was January would be a lot better. You sure can't just pop it out the door and expect people to respond quickly, because it's a change in their process.

And from most people's perspective, their process is more important than FERC's process, and their process is more important than the electricity bill. Their process is getting America's business done, and they want to feed this into it in a way that integrates their work without having to focus on it and divert from other things they're doing in a rush.

There are other points about how the tariffs are going to be put together for demand-response programs: What the collection mechanism will be; whether it gets assigned to different areas. Some of it's hanging fire on getting standard market design and LMP in place, but a lot of it, I think, is moving forward pretty productively.

So I have high hopes that there will be tariffs, which, in the words of the letter that we sent you before, the New England commissions can consider with serious and expedited consideration, and a good chance of putting stuff in place by next summer that will make things significantly better.

That leads me to my one big concern. We've heard the word, subsidy, thrown around a lot this morning. I do agree that you can have subsidies for load response, and I think you do if and only if you're paying the respondent more than you would have paid a generator.

Anything short of that, I don't think is a subsidy, and I think that it's corrosive and really almost poisonous to use that language there.

This is I think from an old utility mindset that's not evenly balanced between the interests of buyers and sellers. And I have to tell you that when I see it emerging in places like the first question on the Staff questions for today's meeting, it raises a serious concern that goes partly to whether people actually understand that they're asking an end user to give up something that they have a right to.

An old client of mine with real estate investment trusts. If you ask them to give up an option value to build in Times Square and told them that it was a subsidy to pay them for it, because after all, they were saving the cost of putting up their skyscraper, they wouldn't have thought that was a rational argument. You shouldn't think it's a rational argument here.

Similarly, if you are paying the energy clearing price to people who have bid in at a lower price and said they could serve at a lower price, you can call that a subsidy if you want. But unless you're going to call it a subsidy, you shouldn't be calling pay a load response, anything up to that level, a subsidy. And when you do, and when your staff notices persistently do, it creates a perception, a real one, that you don't fully understand the balance between buyers and sellers.

And I have struggled for a long time to be supportive of the Commission's efforts to have market-based rates in wholesale markets, because I know there's questions about whether they'll really work. But I think that the benefit is worth the gamble of trying. If you can pull it off, there will be some real gain.

But that calculus gets recalculated if there's a feeling that we're going into it with a sensitivity that's much more aware of and sensitive to the interests of people who have an interest in high prices and high throughput than we are in the interests of those who are buying out of the market and have an interest in low prices and low throughput.

So I have to tell you that when I see the continuing references to subsidies in this context, it raises a serious concern that goes way beyond how I feel about load response programs themselves.

That's a big issue. I don't want to be rude about it, but I do want to be blunt about it. A lot turns on that, in my perception, and I think in many others.

Having said that, I want to get back to the positive part, which is that I do think that there's a real serious chance that load response programs that will make sense for New England can be put together and that they're making real progress on doing that.

FERC's role in providing people has been important. The role in providing some money for consultants has been helpful. The most important part, though, I think is the human commitment of people that understand the SMD process and how the parts fit together. Compared to that, $10,000 or $50,000 here or there is nice, but secondary. The intellectual, human capital commitment is huge and deeply appreciated.

So with that, many thanks.

CHAIRMAN WOOD: Happy anniversary.

COMMISSIONER BROWNELL: And thanks to Commissioner Dworkin for his serious leadership on this issue long before we weighed in and joined in partnership, and we appreciate your hard work. And get home so we don't get into trouble.

MR. DWORKIN: Okay. Thank you, folks.

CHAIRMAN WOOD: Okay. Where are we on this other issue, Steve?

MR. RODGERS: I don't know if upon consideration of the information that we passed on from the application, if that sways anyone's views or clarifies anyone's views better on the Commission.

CHAIRMAN WOOD: What's your thought?

COMMISSIONER BREATHITT: I think that your reading that language clarifies in my mind that there is a distinction that the people who sponsored the declaratory order have made between voting and participation. And these are open meetings, and I'm just not willing to cut off participation. I think they clarify that there's one vote.

And in the other orders, the parties, one of my staff told me, asked for that language. The Commission didn't assert it or demand it. So I think there's a distinction.

COMMISSIONER MASSEY: Well, there's already language in the order that goes halfway toward the point I'm making in saying that we note that in recent orders that we've issued, each market participant is only permitted to participate in a single stakeholder group.

So we make that point. If that's not our policy, why do we make that point? And I think it should be our policy. So that's why I'm proposing the amendment. I do not want a dominant player to have an overwhelming influence on the deliberations of the SAC.

CHAIRMAN WOOD: Nora, what's your thought?

COMMISSIONER BROWNELL: I agree with Bill. I think that there are many ways in which people's views can be felt, but I think it's important to send a message that we want everybody kind of on an equal playing field. And I do think the resource issue, I've seen it play out in the collaborative process. And whatever we can do to ensure that that doesn't occur here, I think we're doing our job.

And I also think there are lots of opportunities for the big players to have their voices heard. So I do support Bill's amendment.

CHAIRMAN WOOD: I'm weighing in on Bill's side too. In our experience, this was an issue that came up, and I think you've got to make it clear you kind of need to pick which segment you're working with and make your input felt through that segment. So I would be comfortable with what Bill has suggested being in this order here, and actually reflecting what I think is what I understood to be the policy in the prior orders.

Are there any other issues here? I wanted to just say a couple of comments on the order. I think actually when we talk about SMD and RTO dockets informing each other, this is exactly what we mean with regional variations. We did it with RTO West.

I think actually the language we talk about here, we should put in the RTO West order. It was implicit there. But I think it needs to be explicit. Basically, that we've thought about these issues. We've looked at the world as it needs to be to reduce seams and to remedy discrimination, and we've seen this live proposal here, and we find that this meets the standards that we have articulated in prior RTO orders, and that we've also articulated again in the recent SMD NOPR.

And I think it is important for us to just say these issues, we're not going to go revisit them again next summer. We've got to get people onto getting software implemented, getting detailed business and commercial rules written, getting the NAESB/NERC people together on the issues that we are going to charge them to do, that I don't want to go back and say, well, the ISA needs to have a different board structure or something like that.

I think those kind of issues that -- and they're actually in this order only a couple that we actually do give definitive response to, because there are only a couple of issues that the sponsors asked us to give such a response to. But I do think it's important to draw a consistency with where we've been on RTO orders and with what we're learning on SMD.

And I think it is appropriate, and I think it's actually facilitating of competitive wholesale markets to move today to say these issues look great, they look fine. We'll make sure that you don't get the March surprise and have to do those again.

So I think this is a good, competitive, efficient market design. The proposal of market rules with LMP, with the pricing methodology, with the day ahead and real time markets is at its core what the SMD is at its core. And that is about getting efficient wholesale markets to work in all parts of the country. And this is a totally different issue from whether, as we are learning from our visitors here today, that retail markets are opened.

This is kind of the basics. This is the foundation is the wholesale market working in a regional method. And I think this proposal, to my pleasure, actually gets a nice template out there for other folks to look at and think about. And I thought it was quite well done and was pleased to see a nice, comprehensive approach to the alternative governance structure that we've seen before, as Linda pointed out, and certainly a response to the state commissions down there that we are listening to on the pricing issues that they care a lot about.

So I think the order looks good. I support is as amended, and that's all I've got to say.

COMMISSIONER BREATHITT: Are we ready to vote?

COMMISSIONER MASSEY: I don't want to belabor the point, but I don't know whether I could ever get comfortable with this language tying our hands like this. I do think it's unprecedented. But I didn't know this was our policy until this language was proposed, and frankly haven't had time to think through all the implications of it.

So my inclination at this point is to say we should not tie our hands in this way. So I will be dissenting on that point, Mr. Chairman.

CHAIRMAN WOOD: Thank you. I think that's fine. All right. Let's vote.

COMMISSIONER BREATHITT: I am going to vote on three orders at once, because I have to leave, Madam Secretary. I'm going to vote out the CTRANS order which is E-32, with a partial dissent on the governance issue.

I'm voting out E-44 with a partial dissent on the governance issue. And I'm voting M-1 affirmatively.

COMMISSIONER BROWNELL: Aye. On the CTRANS order, right?

CHAIRMAN WOOD: Yes. And I need to go with her. So I'm going to do the same thing she did.

COMMISSIONER MASSEY: On the CTRANS order, I will be issuing a partial dissent.

CHAIRMAN WOOD: On the CTRANS order, I vote aye. I, like Linda, have to go to the confab in Louisville, Kentucky on a 2:05 flight. So I will vote aye on the West Connect order, and I will vote aye on the accounting order. If the preference is to push those off based y'all's discussion, we'll do that as needed.

COMMISSIONER BROWNELL: I have an issue on what it is we are approving in the scope of the West Connect order in that my reading is that there, with one exception, are no jurisdictional entities left to join. So my inclination would be to approve that in terms of scope with the hope that the public power entities who have not yet signaled their intention would in fact join and the one jurisdictional utility I think in Colorado would join.

I'm just not sure. The language is unclear to me. And I just, if you could quickly comment. I know you have to go.

CHAIRMAN WOOD: I would join you in a concurrence on that issue, since Linda is gone. I do think the language on page 24 of the order addresses the scope issue. And it might be a little soft, so I'll be glad to join you on that.

So show me as a support with separate statement. And I apologize to the panel for having to leave, but I have to go.

(Chairman Wood and Commissioner Breathitt depart the meeting.)

COMMISSIONER MASSEY: That's what I get for dissenting on his language.

(Laughter.)

COMMISSIONER BROWNELL: (Presiding) Okay. You can give me directions. We need to vote on E-44. We've heard two votes. We have a concurrence with Pat. I will vote aye and concur as well.

COMMISSIONER MASSEY: What are we talking about here?

COMMISSIONER BROWNELL: E-44.

COMMISSIONER MASSEY: What is that?

COMMISSIONER BROWNELL: Do we have a presentation? I'm sorry. West Connect.

SECRETARY SALAS: Arizona Public Service Company.

COMMISSIONER MASSEY: Oh, is that West Connect?

SECRETARY SALAS: Yes.

COMMISSIONER MASSEY: Oh.

COMMISSIONER BROWNELL: Maybe we should get the team up here to present.

COMMISSIONER MASSEY: Yeah, I have issues on that.

COMMISSIONER BROWNELL: Okay. All right. I tried.

COMMISSIONER MASSEY: I'll try to help the Chairman on it, but I do have some issues.

SECRETARY SALAS: For the record, the next item for discussion is E-44, Arizona Public Service Company, with a presentation by Chris Thomas, Eugene Grace and Mike Coleman.

MR. THOMAS: Good afternoon. E-44 is an order addressing a petition for declaratory order by the four public utilities located in the Desert Southwest: Arizona Public Service, Tucson Electric, Public Service Company of New Mexico, and El Paso Electric.

Concerning their proposal to form a for-profit

RTO to be called West Connect, the order accepts, with certain modifications, the West Connect governance structure. It also finds that the scope of West Connect is acceptable and encourages the parties to add nonpublic utility members to the scope of West Connect.

The order accepts a number of the specific elements of the West Connect proposal, including license plate rate design, ancillary services, procedures for addressing parallel path flow, and voluntary conversion of existing contracts.

The order accepts the applicant's proposal for a physical rights congestion model at startup, but directs the applications to hold further discussion with stakeholders to develop a congestion management program that reflects market-driven solutions to clear congestion.

The order also accepts their market monitoring proposal, but in light of the ongoing discussions of the entities proposing to form RTOs in the Western Interconnection, requires the West Connect applicants to continue using the Seams Steering Group to address market monitoring as a West-wide proposal.

Thank you.

COMMISSIONER MASSEY: I'm concerned about the call in this order that accepts the scope and configuration of West Connect. I'm aware that in that region of the country, some nonjurisdictional companies like WAPA and the Salt River Project are significant players. As I understand it, the West Connect companies and WAPA and Salt River in many areas are sort of integrated like this. Am I right about this, Mr. Coleman? Not that this is a perfect description of it, but --

MR. COLEMAN: There are a number of joint use transmission lines in the Desert Southwest, and Salt River does operate a number of transmission lines under contract for parties. An earlier question as to whether or not Western and Salt River represent insignificant parts of the Desert Southwest transmission system, I don't think on a factual basis that we could say, no, they are not insignificant. Western does have a number of circuit miles there, and Salt River does make a claim that it is a strategic player in the Southwest. Both have participated in the development of this proposal as is noted in the order, though.

COMMISSIONER MASSEY: I'm aware that they're not jurisdictional companies. But I think it's true that they are significant, substantial players in that region of the country. And our policy in Order 2000 is not just scope, but scope and configuration. And we make a number of arguments in Order 2000 about the importance of the configuration.

I ask the question, are the WAPA and Salt River Project grid facilities more integrated or less integrated with those of WestConnect? Are they substantially integrated with the WestConnect members; would you say that's an accurate statement?

MR. COLEMAN: Although we are talking relative degrees here, I would say that, yes, they are integrated, because there are a number of transmission transactions that require the use of not only the facilities of the public utilities that have formally filed the WestConnect proposal, but as well as Western and the use of Salt River's operation of some of those lines in order to make the deliveries. I don't know if that answers your question or not.

COMMISSIONER MASSEY: So I think that we can safely assume that these entities control significant facilities in terms of the trade patterns, constraints, flows, and so forth? Would that be an accurate statement?

MR. COLEMAN: Yes. I wouldn't disagree with you on that.

COMMISSIONER MASSEY: Order 2000 requires a configuration that allow the RTO to perform congestion management, one-stop shopping for transmission service, to manage parallel path flows, engage in very useful market monitoring for the whole region, to have a good planning and expansion model.

I'm concerned that without these significant players, that WestConnect may not meet our scoping configuration requirements, and my own view is that we should leave this issue open and tell the parties to continue to work on it, perhaps provide some sort of mediation or some sort of service, but send a signal that we -- a very firm signal that we believe that the participation by these parties is very significant to having adequate scope and configuration for this region.

And that's my opinion on that question. As I understand it, the Order says we find acceptable, Applicant's proposal for developing an RTO that includes all jurisdictional public utilities located in the Southwest, and that allows for participation by non-public utility entities.

I do applaud them for having an RTO proposal that allows for the non-public utility entities to participate, but I do think that additional efforts are necessary, additional filling in the holes, so that we don't have another Swiss cheese type proposal, a Swiss cheese type RTO before.

I think it would be very important to fill in those holes before we say, yes, this meets the standards of Order No. 2000.

MR. COLEMAN: Commissioner, I mean, I'm certainly not debating your opinion, but to point out a couple of things that are in the Order, we do note that the governance structure that the WestConnect Applicants have put together, I think was specifically designed to accommodate participation by Salt River Project, in light of its unique status, as well as Western Area Power Administration, as the Federal Government entity, and the other coops that are there in the South, and that the Order does strongly encourage the Applicants to continue discussions to accommodate non-public utility entities and thereby expanding the scope of WestConnect. I would think, it's my personal observation that these other entities are looking to the guidance in this Order in order for them to be able to take positive steps in terms of potentially joining the RTO.

They did participate in this, although they -- in the development, although they are not signing on or have joined as members at this point right now.

COMMISSIONER MASSEY: Wouldn't we accomplish the same goal by saying we have concerns about the scope and configuration, without these major players participating; that we'd like to see additional efforts to get them involved with substantial additional participation by these entities?

We would probably conclude that there is sufficient scope and configuration. That would then give them the clear signal that they need, it seems to me. There's maybe disagreement on that, but that's my opinion about it.

MR. CANNON: Commissioner, I think the concern is that they move forward; that we not give undue leverage to the non-jurisdictionals in terms of their future negotiations on sort of what the appropriate RTO structure and market structure should be in the Southwest.

I think I would agree with you wholeheartedly, if there were jurisdictional entities that controlled these same types of facilities who weren't participating, but my answer is somewhat different in terms of non-jurisdictionals, just because I think that this Commission's ability to encourage them to participate is limited to exactly that, to encouragement.

And so that's sort of what's driving me to think that it's better to accept the scope, accept the parties to continue to work to expand that scope, and, indeed, to encourage them to continue to work with their California neighbors, as well as with the Northwest RTO to, to use the Chairman's phrase, to continue to iron the seams that will exist between these three separate organizations.

COMMISSIONER BROWNELL: I would vote to adopt the Order, as written, noting that Pat and I will be writing separately to encourage the involvement of those who have not chosen to actively sign on at this moment in time, and would note Linda's affirmative vote, as well.

COMMISSIONER MASSEY: Well, I appreciate all the discussion about this. I just can't, with a clear conscience, vote to say that as currently configured, this meets the standards of Order 2000, because I don't think it does.

So, I'll be dissenting, in part, on that point.

COMMISSIONER BROWNELL: Thanks. M-1, and I think we have a presentation.

SECRETARY SALAS: The next item is M-1, Accounting and Reporting of Financial instruments, comprehensive income, derivatives, and hedging activities, with a presentation by Mark Klose, Jim Guest, and Julia Lake.

MR. KLOSE: Good afternoon. This final rule is part of Staff's ongoing effort to address emerging developments in accounting and financial reporting that affect the Commission's regulated entities.

M-1 is a final rule that establishes new asset and liability accounts for the reporting of derivative instruments and hedging activities. It also establishes a new account to record items of other comprehensive income, and changes to the existing accounting requirements to permit certain investments in securities to be reflected at their fair value, rather than historical costs.

In addition to the new accounts, the final rule revises the Commission's annual report forms to provide complete and full disclosure of these transactions.

These changes are important to the current requirements, which do not clearly show the extent to which jurisdictional entities are using derivative instruments for hedging or trading purposes.

The new requirements will add visibility, transparency, and uniformity for the accounting and financial reporting for these activities. Specifically, the Commission's annual report forms will see the extent to which companies have engaged in hedging activities, and those activities the entity considered trading in nature.

Just as importantly, these transactions will be measured on the basis of fair value. Investors and other users of the financial statements are of the view that fair value is the most relevant measure for certain assets, including derivative instruments, because it reflects the current cash equivalent of the entity's financial instruments, rather than historical prices.

With the passage of time, historical prices become irrelevant in assessing present liquidity or solvency. There are a number of acceptable methods used to determine the fair value of a derivative instrument. The best way to determine fair value is to observe active markets and observable prices.

Where active markets do not exist, management uses various models to estimate their value. The final rule requires companies to disclose in the Commission's annual reports the key inputs and assumptions that were used in their fair value models.

In this manner, the Commission and other users of the Commission's annual reports can assess the reliability of the amounts reported. This disclosure requirement is similar to the one recently adopted by the SEC.

By recording derivative instruments in the financial statements at their fair value, the Commission will gain better insight into which entities are using derivative instruments, what risks they are hedging against and not hedging against, how effective the hedges are in minimizing those risk, how much of the derivative activity is speculative in nature, and what the entity's derivative exposure is in the marketplace.

Finally, the final rule severs the inquiry on whether independent and affiliated power marketers, gas marketers and power producers should continue to be eligible on a case-by-case basis for certain waivers of the Commission's regulations.

It directs the Staff to hold a series of technical conferences and outreach meetings on these matters.

This concludes my presentation, and we would be happy to take any questions.

COMMISSIONER MASSEY: I have a couple of questions about this. When we originally made this proposal, when was that? When was this --

MR. KLOSE: Back in November I believe.

COMMISSIONER MASSEY: November of last year?

MR. KLOSE: Yes.

COMMISSIONER MASSEY: I thought this was moving in the right direction because it seemed to me that -- and this is the so-called mark-to-market accounting rule.

MR. KLOSE: Yes. Part of it, yes.

COMMISSIONER MASSEY: It may do more than that. But it essentially says the Commission's -- does it say that our policy is also mark-to-market accounting, or simply that we want in the Uniform System of Accounts, the jurisdictional entities to report any mark-to-market accounting activities?

MR. KLOSE: I view it more as a reporting issue, that we are creating new accounts to capture these amounts on the face of the financial statements, because companies are required to use this new accounting model for reporting to the SEC or anyone else.

COMMISSIONER MASSEY: Yes.

MR. KLOSE: And it's just a matter of keeping our annual reports in line with the filings of the SEC or others.

COMMISSIONER MASSEY: Right. Do we get reports? How are derivative instruments reported to us now? Do we get those reports?

MR. KLOSE: Well, I believe the short answer is no, that they may be reported in the accounts. Since we have no specific guidance, it is unclear exactly what accounts they are being reported to us or even maybe the method that companies are using to report these amounts to us. So it's somewhat of an unclear area, and we're trying to give more guidance.

COMMISSIONER MASSEY: So the concern of our accountants is that we don't get nearly enough information on derivative instruments.

MR. KLOSE: Exactly.

COMMISSIONER MASSEY: It may be a major area of activity that is very relevant to the Uniform System of Accounts disclosures that are made in the filings that are made here. But we don't get that information now and we think we need that information and want that information.

MR. KLOSE: Yes.

COMMISSIONER MASSEY: And we believe that our policy ought to be consistent with the policy o FASB -- what does FASB stand for?

MR. KLOSE: Financial Accounting Standards Board.

COMMISSIONER MASSEY: Financial Accounting Standards Board.

MR. KLOSE: Yes.

COMMISSIONER MASSEY: Our policy ought to be consistent with FASB policy and the SEC policy. Have I stated that reasonably?

MR. KLOSE: Yes. I mean, I think that to the extent that we can keep our accounting and reporting rules in line with FASB and the SEC, it reduces the burden on companies to preparing two sets of financial statements, two sets of the results of operations and so on and so forth.

I mean, there may be certain circumstances where the Commission may, for whatever reason, decide to collect information on a different manner, or have it reported differently. But by and large, we are in conformance with GAAP.

COMMISSIONER MASSEY: So we made that proposal back in November, and I thought it was a good idea. Then came the disclosures that perhaps one or more major market participants had actually abused mark-to-market accounting, and in fact there was a story in the Washington Post by Peter Behr that said that when Enron had advocated mark-to-market accounting and when they achieved that with the SEC, a cheer went up on the trading floor.

And I have no idea bout the facts of that, but the implication was, this is an opportunity to make more money somehow. And I want you to comment on this issue, because once I became aware of that, I became concerned that perhaps even mark-to-market accounting needs to be updated. Perhaps even it is not state of the art, and I'm assuming that any accounting rule can be abused.

MR. KLOSE: That's correct, yes.

COMMISSIONER MASSEY: Whatever our policy is. And that may be what we're talking about here. But please comment on the issues that I've just raised.

MR. KLOSE: Well, accountants will have different views on the same matter. One of the issues dealing with this idea of mark-to-market is that the investor is better served by seeing the current state of the particular asset, rather than the historical cost of the particular financial instrument, that it may be better to show him or her what the current value is.

The question then becomes, what method do I use in order to show the change in the value of the instrument? When we talk about mark-to-market, I think we're talking about looking at an observable market with an observable price. The problem I think becomes not so much in mark-to-market, but in marking to a model.

What happens when we're looking out maybe, you know, six, ten years out into the future? How then does the manager estimate what the current value of that particular instrument is?

COMMISSIONER MASSEY: So that's where an abuse could occur?

MR. KLOSE: Exactly.

COMMISSIONER MASSEY: If the manager had too much flexibility in determining what the actual value is, because the standards were unclear. Or suppose that entity actually had -- was using some indices in the marketplace, and that entity actually had some undue influence or market power with respect to how those indices were determined?

MR. KLOSE: That's correct, yes. But I think that one of the ways that investors and others can get comfortable with this idea of showing or reporting what the changes are of the particular instrument also goes to the disclosure requirements that we're including as part of this rule.

That in addition to reporting what the management believes is the fair value of the particular instrument, they are going to be required to disclose all of the assumptions that were put into the model. For example, am I talking about the fair value of a derivative instrument that will be settled ten years from now, 30 years from now or next year?

I mean, obviously the farther you go out in time, the more judgmental those inputs become. But if you require the respondent to disclose that -- the model that they use, the inputs to those models -- then you as an investor can make an informed decision as far as the reliability or the relevance of that amount.

COMMISSIONER MASSEY: This rule says we want all of that disclosed?

MR. KLOSE: Exactly.

COMMISSIONER MASSEY: And we want to lay it on the record so that we can understand how you're dealing with these issues?

MR. KLOSE: Yes.

COMMISSIONER MASSEY: And we don't do that now, and we want to do that. That's the whole point of this rule?

MR. KLOSE: Right. We have no disclosure requirement for these instruments.

COMMISSIONER MASSEY: And I'm assuming that once we have these standards that are filed, we can better audit or overview -- do our job with respect to whether the accounting rules are being properly followed?

MR. KLOSE: Yes. We can begin to get our arms around, you know, the extent to which companies that report to us are even using derivative instruments or the extent of their hedging activities. Right now, that information is not captured in the forms. It could be ten percent of their activities or something more.

COMMISSIONER MASSEY: Is there any activity underway in FASB or the SEC to move to even a different standard that we might want to adopt in the future? A standard that is even less likely to be abused?

MR. KLOSE: All I could say is that currently the Board and the EITF, Emerging Issues Task Force, is also looking at the issue of how one determines the fair value of a derivative instrument or any financial instrument, and what rules you would put in place to do that.

Accounting is always emerging. It's always changing, and it's changing to keep pace with the changes in the financial instruments in that industry. So it's always evolving as more financial instruments are created, and we have to keep pace with it.

COMMISSIONER MASSEY: So this rule is about keeping pace with whatever the state of the art is now with respect to this issue?

MR. KLOSE: And may require revisions as we go forward, as new GAAP comes out.

COMMISSIONER MASSEY: Yes. Those are all my questions about it.

COMMISSIONER BROWNELL: Did you want to comment?

MR. GUEST: I was just going to add that I don't think there's a retreat by the FASB or the SEC from using fair value as a measurement attribute. I think there is some discussion underway as to how can we do that better? Are we getting it right? So there's those kinds of discussions that I think are going on in the accounting community in general.

COMMISSIONER MASSEY: And I'm assuming that we're following that closely? That our accountants will stay right on top of this and make timely recommendations to us about what our policy in this area ought to be as FASB's policy evolves, if it does, as the SEC's policy evolves, if it does?

MR. GUEST: Yes.

COMMISSIONER BROWNELL: Good questions. These are very sophisticated financial instruments that in fact add value to the market when they're used appropriately, and I don't want to forget that. But I also hope that -- and we've seen periodic abuses of mark-to-market in various industries over the years. It's interesting that everybody has to try and push the envelope, depending on what segment they're in. They don't tend to learn from each other.

I would hope that as we get this information we could have you present to us the kinds of things that you're learning, particularly about these models. Because I think that's clearly where the abuses have taken place and where the lack of information has not allowed us, or frankly anybody else, to stay on top of it.

So that I think the instruments themselves are valuable. We ought to really have a better understanding of where they're adding value and where the red flags are. So I'd hope -- I don't know when the reporting actually starts and when we'll have enough information to begin to do that analysis, but I think it would be an exercise in learning for all of us.

MR. GUEST: We'd be happy to keep you abreast of all of those activities.

COMMISSIONER BROWNELL: Thank you.

COMMISSIONER MASSEY: That's a good idea. Thank you. I'm ready to vote. Aye.

COMMISSIONER BROWNELL: Aye, noting the affirmative votes of our two absent colleagues. And we're going to take I think a five-minute break before we start. We're not going to let you go for long, because I know you've been waiting a long time and we appreciate your patience.

(Recess.)

COMMISSIONER BROWNELL: Okay, sports fans, on to the next event. Please sit down.

SECRETARY SALAS: We will now continue with A-3, our panel presentations Demand Response Program, and I believe we had stopped at Mr. Gallagher, is our next panelist.

MR. GALLAGHER: I'd like to thank you, Chairman Brownell, and the Commission for inviting the New York Public Service Commission to participate in this panel. I will try to keep my remarks brief and to the point since I know we have a limited amount of time.

COMMISSIONER BROWNELL: We have endless time now, so say it all.

MR. GALLAGHER: Okay. Well, primarily I want to cover three things. First of all, I want to talk about what state regulatory commissions can do to encourage demand response programs. And by example, I want to talk about what the New York Public Service Commission has done in New York.

Second, I want to cite some of the issues and remaining challenges that are out there that we need to deal with in order to achieve more demand response. And lastly, and very briefly, I want to just touch on our response, the Department of Public Service response, to some of the questions raised by the Commission on the incentive/subsidy issue.

Before I begin, I do want to say on one point that I have a slightly different opinion from Chairman

Dworkin of Vermont, where he noted that the results of demand response programs have been very poor and have been much less than expectations.

We believe in New York, I mean, we have just the opposite experience. We went into this two years ago significantly concerned about the load and capacity situation, and expectations I recall from the early meetings to plan our programs were that we would only get a few hundred megawatts from demand response. Now we have ended up, as David Lawrence has mentioned, with registrations of over 1,500 megawatts in our demand response programs. In fact, we're actually hearing great concerns from some of the generators about are we culling too much or what is the impact on prices.

So I believe we met with great success in New York. And what I want to do is focus specifically on what a commission can do to try to achieve that success.

I'm going to cut right to the chase and just tell you the specific actions that the New York Commission took to deal with the demand-supply problem in the state.
First of all, back in 2001, the commission created a demand and supply team of PSC staff, and the commission gave this team a goal of 750 megawatts of new supply or load reductions by the first summer, within eight months of forming the team, and 1,300 megawatts of new supply or

demand reductions by the year 2002, the summer of 2002.

The objective of this team was to leave no stone unturned in where we looked for new supply, primarily distributed generation, as well as demand reductions.

The team we believe met with significant success, and it led to many recommendations and actions by the commission. The major objective of the commission was to get increased price responsive load and also to get, to the extent we can, increased real-time pricing in the state.

One action the commission took actually even before FERC approved the filings of the ISO on the demand response programs, was direct the utilities to file tariffs consistent with whatever FERC approved. The utilities initially came in with their own individual demand response programs, curtailment programs.

The commission rejected all of those proposals with the thinking that we should offer one unified, uniform program across the state that was consistent with the ISO program for two reasons: Both for ease of marketing, for customer understanding. Many of these large customers are in multiple regions, multiple zones, multiple utility service territories. And most importantly, we wanted to make sure that whatever we did had an impact on both real-time prices and day-ahead prices.

So the commission directed the utilities to file these tariffs. Eventually FERC approved the tariffs of the New York ISO, and this was all done on an expedited emergency basis in the state.

The commission also directed all the utilities to file curtailment tariffs for their distribution systems, with the emphasis on Con Edison, Orange & Rockland, some of our downstate utilities where we were having our most significant problems.

The commission also directed all utilities to file voluntary real-time pricing tariffs for all customers over 100 kW in the state. I will speak a little bit more about that when I talk about challenges and remaining issues. But all utilities did come in with tariffs approved by the commission where a customer could voluntarily select a real-time price.

Major commission action was to expand the system benefits charge. And this is funds collected from delivery service customers. And the commission expanded that from $78 million per year to $150 million per year with a directive to staff and to NYCRTA, the organization that's delivering these programs for us, to shift the focus from long-term research to short-term demand reduction.

So the program emphasis was shifted to resource acquisition. And the emphasis was also switched to trying to deliver the enabling technologies that are needed to make programs like those offered by the ISO work. And we felt that that's where we could contribute a great deal.

We directed Con Edison to implement small customer demand response programs, and that program is now underway and it's very successful.

We implemented a state facility load management and energy efficiency program, with the thinking being that we should lead by example and not call on others to act if we're not acting ourselves.

We implemented an expanded customer education and outreach effort across the state, trying to get a uniform message about demand response that customers could understand a single message, understand what programs were available.

And lastly, and this was just this past year, to better coordinate all the state agencies -- and there are many state agencies involved in these programs, from the power authority, New York Power Authority, Long Island Power Authority Department of Environmental Conservation, NYCRTA, PSC. There was a governor-organized task force that met weekly to coordinate among the agencies to make sure there was no red tape put in the way of any of these programs.

Now I want to just take a few moments to touch on what we see as remaining issues and challenges that we have to address if we're really going to achieve the full potential for demand response. And here I'm talking primarily about New York, but I think these issues and challenges really apply to most states around the country.

First of all, we need to have a greater number of customers seeing real-time prices, whether they're on utility tariffs or if they're with a competitive company, they should be seeing real-time prices, or having the option of shifting to a competitive company and entering into a long-term contract. We're going to continue working with the utilities and competitive companies to ensure that this happens.

We also need to continue with the enabling technology programs. We have actually in New York with the system benefits charge, we are installing interval meters at no cost to the customer. So we have put the money into making sure that customers basically have minimal up-front expense to get involved in demand response programs. We're also encouraging distributed generation. We're encouraging energy management systems, controls, everything that would allow them to respond to improved price signals. And we hope to expand those activities.

We have to find ways to encourage large customers, especially in urban areas, to participate in demand response programs. We are finding that the large customers upstate in New York, primarily industrial customers, find it easier to respond. It's easier to turn off an electric arc furnace on short notice from the ISO. But if you're a skyscraper in Manhattan full of 25 different businesses, probably owned by someone in Germany, where energy costs account to less than one percent of your total rental costs, it's very hard to make the sale.

Again, that's why we need to have improved price signals.

We need to find ways to improve our day-ahead demand response program in New York. This is the demand bidding program which focuses on reducing prices rather than the short-term emergency programs. The reason is because the short-term emergency programs are focusing on 20, 24 hours per year. But we really have to get the programs in place that focus on the rest of the year. And we're hoping that that is the next place we turn within the state in terms of increasing customer participation.

And we need to continue our education of customers, and we need to continue our outreach to customers, that they are aware of the power supply situation.

And lastly, we need to make sure that we get new plants built in the state, whether it's new large station plants or distributed generation. We're trying whatever we can to accelerate that schedule.

I would say that the one lesson learned, at least what I see with the New York experience, and this has been cited by -- in fact, there was a recent study by NARUC of the various demand response programs of the ISOs around the country. The one thing I think that worked well in New York was coordination among all the parties, coordination between the PSC, the ISO, customers, the market participants, curtailment service providers -- everyone trying to develop a program that worked.

The failures in many states around the country were agencies or organizations going in different directions from one another, ending up in customer confusion and program performance that was much less than expectations.

Lastly, I just want to touch on some of the questions that were raised by the Commission. And I think I can do this in 30 seconds or less. Yes, we believe incentives should be continued for both the emergency and the economic programs.

We believe that the incentives that are provided for emergency programs may need to be long-term. They may need to continue even after we have a competitive market, to ensure that we have that resource available in the event of an emergency.

We believe the incentives for the economic programs should be continued at least during the transition to competitive markets until we can get improved price signals and give customers greater flexibility on how they can respond to those price signals. But in the long term, we believe they may not be necessary.

So with that, I'd like to thank you for the opportunity to speak.

COMMISSIONER BROWNELL: A couple of quick questions for both you, Jim, and Steve, I'll start with you. But Steve, you can add on. I'd like you to speak to three things if you would. Could you say more about some of those enabling technologies? Because I think the Staff, led by Alison Silverstein, is really looking at that as the next opportunity to push the envelope. Could you say a little more about the interval meters?

I think, Steve, you referenced a small retail program if I can remember before the break, if the brain cells go that far back, kind of what's your experience to date, if you have any, or how do you intend to educate and measure the outcome.

And then, Jim, if you would, you talked about the coordination among agencies, and I think that's important. Was that a PSC-led -- who kind of was the king of the mountain there?

MR. GALLAGHER: The first year it was primarily, at least within the PSC, it was obvious to the staff that were participating, and we then recommended to the commission, that we needed to coordinate on the implementation of the programs. And the decision was, the commission did have to make a decision: Does it go with individual utility programs, or does it go with uniform programs consistent with the Independent System Operator? And staff recommended they go with the uniform program approach.

The second year of the program, the governor's office got involved, and the governor actually put his chief energy person on this group to chair the task force. And this was to get all the agencies involved and to basically make sure things were happening. And it was a very effective process, especially the group spent a lot of time dealing with environmental regulations and how do we cut through that red tape.

On your second point about enabling technologies, we are spending about 60 percent of the $150 million per year on demand response enabling technologies and programs. A good amount of that is going into things that better allow customers to react to price signals and also allow them to participate in the ISO programs.

We're supporting things such as -- I mentioned the meters. We're full subsidies up to $3,000 per meter for a customer that will participate in a demand response program of the ISO. And the range of programs is very large. But I would say the next phase or the future directions in terms of technologies that we're beginning to see are the Web-based enabling technologies where customers will see improved price signals, where the ISOs can actually send improved price signals out to the customers, but even allows the customer to control and automate a lot of their systems.

And we had a pilot program underway this year. It's still underway, where we have ten different vendors of these systems out with the systems deployed, and we are comparing the experience.

And I want to make one other point about that in terms of opportunities. New York City, for example, we have 400 large commercial buildings that represent 2,000 megawatts of load. Not one of those buildings is seeing -- or customers is seeing a real-time price. And they did not enroll. In the New York City area, we have voluntary real-time pricing, and not one large commercial customer enrolled in our real-time pricing program.

So we need to take a hard look at what is it going to take to get those types of customers involved in real-time pricing, and what type of enabling technologies would make it an easier sell.

MR. FERNANDS: Chairman Brownell, I would --

MR. MILLER: Seize the moment.

(Laughter.)

MR. FERNANDS: The first one, enabling technologies. By far, New York is one of the areas that has best funded a wide variety of vendors through NYCRTA where they created incentives for partnerships between companies that provide the data connections and pager technologies and all those technologies to give customers the signal, and some automatic control technologies as well, and form partnerships between customers, the vendor, and the load-serving entity.

So there's a three-way partnership that NYCRTA, through the state, to helped to orchestrate and helped to fund. And that brought down significantly the cost of a lot of projects for our customers. A lot of it had to do with customer, again, being able to see what their baseline was so that they knew if they dropped so much, they'd actually get paid for it, without any type of technology. It's sort of a guesswork, and then after the fact you figure out how much you made.

So there was a lot of that happened in New York. And I would compare that to New England who might have picked one vendor originally and didn't have a lot of experience with other vendors, and PJM, which just didn't do anything with the vendor side but put out the price signals, and some vendors did in fact participate, as we heard earlier, from Constellation, that they did in fact hire -- I think they mentioned Power Web as a vendor.

As far as interval meters go, my experience is small customers. This is something that's near and dear to my heart, because I think that this is a major untapped resource. I know that many people like myself aren't as good as we'd like to be when we leave the house, when we're not around, and leave the air conditioner high, and we don't know if this happens to just be a warm day and the price is high, a little bit high, or if this in fact is going to be the peak day when we leave the house in the morning.

There's a control technology that various people have installed that can be either a thermostat control technology or air condition control technology. LYPA is a good example of this. In New York, I believe Con Ed also is a good example in their new program.

Usually what you do is you install a sampling of interval meters that you're able to do a statistical measurement of what the performance was, as opposed to having every single customer interval metered, and you also allow for somewhat of a lag on the data, so it doesn't have to be instantaneous response, knowing that, okay, right this second we had a thousand houses reduce.

And that, as long as there is a recording device of when the signal went out, and there are samples on statistically relevant number of houses, I believe that you can have effective programs. This is definitely the case in PJM where they've had a long history of allowing small customers to participate in the ALM program. In particular, you can look at PEPCO Power Watchers as a good example of this, and GPU's program.

So this is something that I believe that the technology is there for various types of programs. I think it's now trying to bring them into the wholesale markets where they can actually get paid. Because currently, I think the problem is you have a profile, you have a residential profile, as you all know, and if you're a load-serving entity and you serve a residential customer, the matter that you controlled -- you hit a switch that made them reduce during that peak day, a kilowatt.

Well, the utilities will look at it and say we'll just drop your entire monthly profile by one kilowatt hour. And so without the wholesale markets to be able to sell that kilowatt into, they are essentially excluded from participation. Does that answer your question?

COMMISSIONER BROWNELL: It does. We'll be interested to see the results of the comparison of your vendors, because I think there are some wonderful opportunities out there, and on an ongoing basis as you're evaluating response, that would be helpful to see.

And I have one quick question for you, David, and I'm sorry to keep you waiting. In the ongoing discussions with your friends in PJM and New England, I'm assuming that as part of seams discussions or whatever discussions happen to be the committee topic of the moment, you're talking about the results of demand-side management programs and what's working and what's not and sharing information and maybe looking towards some common programs?

MR. LAWRENCE: Yes, we have been doing that. We are part of the NDRE process and have been working pretty closely with New England and have also talked with PJM periodically about all of our programs. We've shared a lot of thoughts about these things, and I hope down the road we can introduce some real uniformity in them.

MR. LOUGHNEY: Thank you, Commissioner Brownell and Commissioner Massey, for having me here today. I appreciate the fact that the Commission is looking at this issue. It's an important issue. It's a very important issue to the New York consumers for sure.

My law firm represents Multiple Intervenors, which is made up of 53 of the largest industrial and commercial end users in the State of New York. And through Multiple Intervenors, five of our members are members of the ISO. We act through Multiple Intervenors at the ISO committees and the working group level.

The committee process I think -- I'm just going to back up something Jim was saying -- has worked very well in New York in terms of demand response. We've been able to get beneficial programs started and in place and make changes along the way as needed. The review process is constant.

And in this regard, I think there's some kudos for the leadership role that the New York ISO and the Public Service Commission have played with respect to harnessing sometimes very diverse forces.

Most of the action has been through the Price Responsive Load Working Group, which is one of the ISO working groups. And to show you the commitment of the end users to that, the end users have now taken on the chair of the Price Responsive Load Working Group. In fact, I've been acting as that chair.

And I think this all goes back to the year 2000, the first year of unregulated prices, the prices were quite high, surprisingly to our members, and we made a commitment to demand response as a way of responding to the high prices.

My second slide, I'm going to skip over the description of the three programs in which the customers participate, because Dave Lawrence already did it. I will say the important thing from my standpoint or from the standpoint of our members is that we do have the ability to get paid for capacity and for energy. I think that's a little different than some of the PJM programs.

We're called Special Case Resources in New York. You get a capacity payment under that program, and then you can also get paid for the energy that you supply when you were actually called on and you curtail as called on. And from the beginning, I think one of the priorities that we've had is to ensure that customers could receive adequate compensation by participating in these markets, and we see them as distinct markets. One is for capacity and one is for energy. The generators get paid for both markets, and we saw no reason why the loads shouldn't also be paid for them in both markets.

The SCR and EDRP programs have been very successful. I think the important thing there is the linkage of the ability to get paid for capacity and energy. From talking to our members, because this came up recently, there was some discussion in our potential -- something that's coming down the road. But we are changing the programs. And there was some discussion about making the SCR program payment of capacity only. And frankly, it would have I think killed participation in the program if they couldn't get the energy payments also.

The customers that we represent participate primarily because they see it as a reliability issue, but they also want to participate because they feel like the more competitors that are in the market, the better off the markets will be.

So they want to participate, but there is a big hurdle internally for any end user to participate, and there has to be adequate compensation for them to make that decision to sell it internally to their managers.

So the SCR program alone with the upstate capacity market running at $1 per kW per month would not have been sufficient to sustain I don't think the number of members that are currently in these programs.

So those programs have been very successful. The day-ahead program, the economic program has been lagging behind somewhat, and that's unfortunate, because we really view that as the most important of all the programs. That's the one that's going to provide the day-in and day-out competition for the generators. I think the program is somewhat complex for people who are not in this business who have to make a decision as to how to bid on a day-in, day-out basis.

And the other thing is that there is a penalty there, a noncompliance penalty, if you don't curtail as you said you would.

So those are things that we really need to work on, and I think the Price Responsive Load Working Group is going to be taking those up fairly quickly to try and solve the day-ahead program and increase participation.

I think to talk about the New York perspective on these programs, on the current programs, just to echo what some of the speakers have said, the utility-sponsored programs really did not work. The sharings were not equitable in terms of the amount of work that the end users were taking on. So the disproportionate sharing was a big cause of that failure.

We do believe that loads should be able to participate in all markets that they can qualify for. That includes reserve markets, and that's something that we want to start to push within the New York ISO, because we do have members who can participate in the 30 and maybe even the 10-minute spinning reserve markets.

We think that the New York programs provide the right financial incentives. Again, I think it's important to recognize how disruptive curtailments are, and there's a big hurdle for customers to make a decision to curtail. You have to take care of labor issues. You have to, you know, decide whether to send people home or not send people home. You have equipment that has to be either taken off line or brought down to a different level. All of these things cost money, and also you have to do all of that in the context of meeting your own customers' demand.

So we do think it's important that there's adequate compensation for these customers who participate in these programs.

And finally on this sheet, I think it's important that the customers be involved in the program design. I think one of the reasons that the New York programs have been heavily subscribed is that we did work carefully with other market participants and the working group and also with the Public Service Commission and the ISO in terms of just making sure that the rules that we came up with were at least something that the customers could deal with.

On a going forward basis, Dave covered the fact that we will be looking in the working group at changes. We've already talked about and approved changes from the working group to the SCR and EDRP programs. The programs will be separated. The important thing there is that SCRs will no longer be entitled to the $500 minimum payment that goes associated with the EDRP program, but they will be able to bid an energy price for when they are interrupted.

I think we are going to continue to look at expanding the small customer aggregation programs. Two things that need to be addressed in terms of shortcomings, the communications between the ISO and the customers are sometimes delayed, particularly when an emergency call is called off and the customer is standing by waiting to perform, and in fact the emergency is over. So the promptness of notification has to approve.

Somebody mentioned earlier, we have the same problem in New York, that there's quite a bit of delay in terms of getting payment from the ISO. You may curtail in August and not get paid until January or February, and that presents problems for customers.

The only other comment that I had, I wanted to agree with what Commissioner Dworkin said. I think that the debate is sometimes colored with this allegation that there's a subsidy to loads and customers. I don't see that there's a subsidy by allowing the customers to receive a capacity and an energy payment and not pay -- and not offset those with the utility charge that would otherwise apply. It seems to me that that's just allowing the customers to participate in the markets.

So with that, I appreciate again the opportunity to speak, and if you have any questions, I'll be glad to take them.

COMMISSIONER BROWNELL: I have three. In the day-ahead market, you talk about program complexities. Is it an issue of program complexities, or is it an issue of educating the potential participants as to how to manage the program? And associated with that is, what are the noncompliance penalties?

MR. LOUGHNEY: In terms of the complexities, it may be more an effort to educate people. I think I agree with you. The program itself is not that complex if you're able to determine what your price is at which you would interrupt.

But I think it's educating people on how to do it and how to monitor what happens in the market, how to make a decision whether or not to bid. I think there's just a natural inertia. You know, the emergency programs I think thrive because when it's an emergency, you can go to your plant manager and say there's an emergency. We can do this, we can get paid for it, and it's a good thing. And it's a once in a while event.

On a day-to-day basis, to bid in, I think there's an inertia within the customer community, and I think that that has to be addressed.

COMMISSIONER BROWNELL: Jim?

MR. GALLAGHER: I would say the difference I would have with that is that for large customers, the rules of the program are probably appropriate, and customers can respond and they have been.

But there are certain things in the program such as a one megawatt minimum bid, and it has to be increments of a single megawatt. For a generator, that's not a serious problem, but for demand reductions, it's difficult sometimes to bundle the megawatts. So you actually get either one or two or three. For example, if you get 1.5 megawatts, you're not getting paid for that .5 above the 1.

So there are things -- I guess to sum up, there are things that we need to do to make the program more user friendly and customer friendly, especially for those nonindustrial customers. There's a great deal of opportunity out there.

MR. LOUGHNEY: And the other question was the noncompliance penalty is you pay 110 percent of the real-time clearing price. So there's like a 10 percent penalty for if you don't comply and you have to clear out in the real-time market, you don't pay 100 percent of the real-time market price. You pay 110 percent of the real-time market price.

COMMISSIONER BROWNELL: Why does it take so long to get paid, Dave? It's not the first time we've heard that.

MR. LAWRENCE: It's probably good to distinguish between the emergency programs and the day-ahead programs. I think in the day-ahead programs for a handful of those that have participated, they have been paid on a timely basis as part of the monthly settlements that we do, actually the month after performance happens.

In the case of the emergency program, because it's been called upon so infrequently, last year's events all occurred in four days straight in August, they were all put together, and it was the first time we had done the settlements on these, and we did not get those payments out until January of this year.

We made significant improvement with the events that we did in April of this year. We did get the payments out in July to people, which is as timely as can be, given that we need at least 45 days to get the meter readings in from the actual load-serving entities. So that time period, April event, July payout is probably optimum for a manual process and manual meter reads that we have.

MR. FERNANDS: Just an option that's been talked about but we haven't decided to go there, is to pay based on what you stated you were going to do, and then you would true up. So there's many other times where that sometimes does happen. The issue comes down to credit. So if you're paid money and then you find out that you really didn't deserve all that money, it's a credit issue.

But that's one thing that could make it a lot faster. And the Billing and Accounting Work Group I know at one point had looked at that.

COMMISSIONER MASSEY: It's an excellent panel. I have no questions, but I really appreciate your coming and participating.

COMMISSIONER BROWNELL: Thanks for your patience. Bill's going to buy you lunch because you were so patient.

(Laughter.)

SECRETARY SALAS: We will now continue with Panel 3, New England's Existing Program. Participants are Henry Yoshimura, Donald Downes, Thomas Austin, Erik Bartone, and Michael Swider.

MR. MILLER: Madam Chairman, can I ask a question? I know that there are a couple of these folks who have other appointments, and I'm wondering if we should ask about sequencing the folks. Is there anybody who has a commitment where you have to be someplace within the hour, for example?

COMMISSIONER BROWNELL: We're going to check, so be careful here.

MR. MILLER: No? Okay. You moved it? Okay. Okay, good. We thought there was a Hill appointment.

COMMISSIONER BROWNELL: Depending on what he was going to say, we could go either way on that.

MR. YOSHIMURA: I am the Manager for Demand Response for ISO New England. Thank you. I have some slides. I don't know if they will be projected. Thank you.

(Slide.)

I guess I should start by saying a little bit about why we are providing incentives for demand response in New England. Right now we are providing incentives for the availability of guaranteed curtailment when reliability is threatened. We believe that this is necessary because we want to diversify the system's, quote, "insurance policy" to help keep the lights on for both planning and operational reserve purposes.

Similarly, we also view that in times of system emergency in particular, demand response may be the only resource available to the ISO in the short run. And certainly it's better to implement a program like that than to incur involuntary load shedding.

Also we provide incentives for the strategic management of customer on-site PAR use at times of high prices. We believe that that promotes a more balanced wholesale market in which the demand side is actively participating in the market as well as the supply side.

Also, we recognize that at the present time that there are numerous barriers which keep customers from making consumption decisions based upon the wholesale price of electricity as it varies over time. And I think my other colleagues on the panel will be discussing some of those.

(Slide.)

The next slide, we show the two programs that we currently over that were in operation in 2002. There's a Class I demand response program and a Class II price response program. The Class I demand response program is an emergency interruptible load program, not unlike some of the other ISOs have described this morning. End use customers in this program offer a guaranteed level of interruption, and these customers are provided an incentive based upon capacity credit and also receive a payment based upon the energy clearing price. And also, if they're located in certain congested zones, we also have a multiplier which we apply.

In the Class II price response program, it's a voluntary program where the participants are paid the market clearing price of electricity when they respond to an ISO notice. And that notice is issued when the market price reaches -- is forecast to reach $100 per megawatt hour or greater.

In 2002, as of the end of September, we had about 221 customers signed up for the programs, representing about 185 megawatts of resources. Most of these resources of any one area are concentrated in Southwest Connecticut. Unfortunately, Commissioner Downes had to leave, and I think he was going to speak to this. But basically we have specific operational and planning reserve issues problems down in Southwest Connecticut, so a big effort was placed to put more of these resources there.

(Slide.)

Turning to the next slide, this shows how our enrollment progressed over the course of the years. As you can see, it steadily increased over time. The dates on the bottom of this slide represents the dates in which we had our price response events. I'll go into some conclusions about this. But basically we see that over time, both programs, the enrollment was increasing over the course of the summer.

(Slide.)

On this next slide, while prices hit $1,000 per megawatt hour one day in August, year 2002 was actually relatively quiet. We had no Class I demand response calls this past summer, so we never called the emergency resources.

There are 12 days in which the Class II price response program was triggered. But in general, the market clearing prices were relatively low. There were very few hours in which the prices got above $100 per megawatt hour. As this slide shows, we had like four hours in which the prices got above $500 per megawatt hour, and they all occurred on one day.

Currently, we are engaged in a comprehensive, independent evaluation of our programs, in order to assess the benefits and costs, and also to try to figure out how to improve program implementation.

On my last slide, this shows that we are going to be offering a much larger menu of programs, going into 2003. In 2002, we have two programs; in 2003, we have four programs, and in a couple of programs, we've actually expanded some of the options.

Just to go over the 2003 programs, we'll be offering a day-ahead demand-response program. This new program will be issued in conjunction with our day-ahead market under SMD. The real-time demand-response program is similar to the existing Class I program, except we're going to be offering more options in terms of how much time we're going to give the customer notice.

Currently, there's a 30-minute notice period, and we're going to offer also a two-hour notice, as well. In terms of our price response program, we're trying to offer more options to allow more customers to participate in what we call low-tech and super-low-tech options, which the type of metering and one notice has to be given back to the ISO, in terms of what the actual meter reads were, you know, the timing of that. We're loosing that to allow more customers to participate.

And, finally, we're offering what we call a real-time profile response program, which is designed for customers without interval meters. The program is designed for, for example -- the amount of demand response that we're going to be measuring there will be based statistically and customers with loads like, you know, direct, low-control air conditioners, water heaters, that sort of thing, those are the types of customers that would participate, but they don't need an interval meter.

So that's my presentation, and I welcome questions.

COMMISSIONER BROWNELL: Thank you. I have been remiss in not introducing the staff at the table. Steve Rodgers, I waited till he left, just to test his -- Gil, we want to welcome him. He's a Presidential Fellow who is on loan from the Department of Energy; Eric Wong, and Scott Miller, and they will be participating in the discussion, although I didn't let them do it in the last two panels, but now you're welcome to show your stuff.

MR. MILLER: There are a couple of things. I know that some of the programs that the ISO has proposed are the subject of comparisons in the NEDRI process. But could you explain to me, because of the relative lack of demand response that we've had over the years, why there would be caps enforced in some of the programs?

For example, there is a proposed $50 floor and $500 cap, and what's the rationale for that?

MR. YOSHIMURA: Okay, there you're talking about the day-ahead program that we've proposed, that would have the $50 floor on the bid, and a $500 cap.

The reason for the -- let's start with the floor. The reason for the floor is that that's basically to try to address a potential free-rider issues where, let's say, you have someone who was going to be offline anyway, and so we want them to be bidding into that market, a little bit higher than where we normally see the market price, which is primarily -- most of the hours of the year, the market fluctuates around three to four cents per kilowatt hour, so we want them to be bidding above that, so that we're not paying them at times in which they would be normally off at certain times of the year. So that's the purpose of that.

The price cap of $500 was put in place for a couple of reasons: One is that we view this day-ahead program as actually an emergency program. I know that some people view it as an economic program, because there's a bidding aspect, but what's important to understand about that program is that it's not -- once you bid and your bid is accepted in the market, you are required to respond.

If you bid a megawatt at, let's say, $200 per megawatt hour, and the day-ahead market clearing prices is at $300, we'll compensate you $300, but that megawatt, we're now expecting to be off the system.

And that particular aspect of the program is a little different than some of the other day-ahead programs that had been discussed earlier.

Because of that, the reason why we put the cap on there is to ensure that when we call -- when these resources are called, actually, that they are available, you know. Every now and then our prices do reach $1,000, and we want them available.

And the last piece of this puzzle is that these resources, because they are required to interrupt, they do receive ICAP credit. So, if they are accepted, they're going to be paid this ICAP credit in addition to whatever the day-ahead market clearing price is.

So when we considered those three pieces together, we put the cap there so that, one, we're not paying for ICAP credit for resources that may actually not be called, even when the price is high. So we put the cap at $500 so that when we're reasonably confident that we will need emergency resources when the price does get above $500, so that's the purpose for the cap.

I think the other piece is that we have a price floor on the real-time price response program. I know that you didn't ask me about that, but that's the subject of considerable discussion in NEDRI.

Currently we have a price floor of $150 -- we propose a price floor of $150 per megawatt hour, for the 30-minute response, and $100 per megawatt hour for the 2R response in the price response program.

We're aware that the other ISOs have a floor of $500, which effectively, you know, encourages participation. You see that big number there, that does encourage participation.

As an organization, we have discussed this, and we're considering raising the floor to that level. We have to go through an internal process and NEDRI hasn't made its final recommendations, but, you know, that is being considered seriously.

MR. MILLER: Just one quick followup on the day-ahead, though: Generation is capped at a thousand?

MR. YOSHIMURA: Yes.

MR. MILLER: Generation gets ICAP.

MR. YOSHIMURA: That's correct.

MR. MILLER: You know, I think that one of the things that we hope to get to is eliminate disparate treatment between supply and demand.

MR. YOSHIMURA: Right. I understand.

COMMISSIONER BROWNELL: Mr. Austin?

MR. AUSTIN: Thank you. My name is Tom Austin.

I am on the Staff of the Maine Public Utilities Commission. I'm trained as an economist, a fact that may become boringly obvious to you by the time I finish.

I wanted to begin by thanking the Commission for the opportunity to be here. In thinking about what I might say today, I wound up beginning with a question quite similar to a question that I believe Commissioner Brownell asked earlier today.

Roughly restated, why are we talking about demand response program, as opposed to simply demand response? Do we really need programs, and if we do need programs, should we be thinking of them as permanent features or temporary features or bridges to get us to somewhere?

And that's mostly what I'm going to talk about. Just to cut to the chase, I think the answer is that we probably will need some kinds of programs, more or less indefinitely, but they're clearly a second-best answer, and, in many cases, the programs are just bridges to get us to a market that really clears in a more functional way.

In thinking about it, a number of people have talked about what they think the goals of a demand response program are. I think there are probably two, at the end of the day.

The first is demand response can and should provide a short-term prophylactic against market power problems. There has got to be something other than Joe Bowring, with all due respect to Joe, sitting there saying that things are out of whack.

We need to get to a point the customers say that at this price, the answer is no, and we don't have that, at least we don't have nearly enough of it.

Over the longer term, and perhaps more importantly, we need to move to a world in which demand can truly compete against supply, in the sense that we simultaneously determine our fleet of peaking units and our fleet of smart buildings and HVAC systems in office buildings.

That's really where we want to get to, and if there is an advantage to competition in this particular realm, that's what it is. I'm also taking a broad view because my impression, having sat through the last five years of the creation of restructuring, is that, perfectly understandably, but with predictable results, we tend to focus very much on the crisis du jour, and make sure we solve that, and sometimes do and sometimes don't create other crises that we then have to deal with five years down the road. My guess is that everybody in the room can nominate at least one, and perhaps several examples.

What do you need for demand response -- program or otherwise? Well, you need to get an accurate price message to customers, and you need to get those price signals to customers in ways that they can reasonably respond to.

I want to talk about both pieces. I want to, I think, talk about the price piece first, getting the prices set right, because we've been presuming in this conversation that we're doing that, and I think there are areas where we need to at least think about that a little more carefully.

Probably my favorite example of trying to getting the wrong answer a little too quickly in New England was, we started off with a market which did not take into account, the locational differences, either in terms of capacity or in terms of energy. We quickly found that we were spending a lot of time sticking thumbs in dikes until we could get around to actually fixing that. What that means, if you think about demand response as a way of balancing generation resources, transmission resources, and demand response resources, is that there should either be no subsidies, no socialization of costs for any of them, or is far distant second best similar subsidies and socializations for all of them?

And it's particularly important, because if we look at the areas where demand response is believed to be most important today, the areas that pop into mind immediately are, in my neck of the woods, southwest

Connecticut and the greater Boston area, and New York City, I presume, but don't claim to know much about, is probably in a similar boat.

So, for demand response to work, we have to treat the alternatives under consideration in those areas similarly, or we'll wind up -- or whichever solution winds up getting the biggest subsidy will be the solution that will, probably uneconomically and probably very slowly, because the people who are being asked to pay the subsidies will drag their feet as best they can, will be the answer.

Second piece: Another thing that we tried to do too quickly last time and are still suffering for is figuring out what to do with capacity responsibility. It is completely clear that we're going to be doing something with capacity responsibility, and that we're going to be doing it for two related purposes:

One is to make sure that there is enough generation out there to keep the lights on; the second -- and my Chairman, Tom Welch, has been particularly strong on this -- is to make sure there's enough capacity so that we don't get wild swings of prices in the energy market.

Now, both are a good idea. As I read your orders, you think so, too. But what we have to remember then is that when we do the pricing at the wholesale and ultimately at the retail level, that not just the energy but also the capacity component of price has to get through in a way which is real to customers.

We have made a lot of progress, I think, in New England. We went to a system that's still in place, but soon to be changed, which heavily loaded the capacity costs in months like April, where they should not have been.

If you load capacity costs in months like April, you can't reasonably expect folks to control their air conditioning use, particularly if you're using a capacity market to dampen the energy crisis, which is the effect of a capacity market, or dampening the volatility.

So the second piece, which I think falls fairly clearly in your world, as opposed to my local retail world, is how the capacity piece gets assigned to specific hours, and the critical importance of making sure that it gets assigned to those hours where the system is most stressed.

One other much smaller point, which goes back to some of the things that Henry, among others, have talked about, and which at least falls in your neck of the woods is that we will undoubtedly have for the foreseeable future, a lot of customers who did not have real-time meters.

I don't know if that's good or bad, but I'm pretty sure it's true. What that means is, for those customers to participate in any kind of demand program, we have to take a fairly careful look at how the load-profiling system works, and our willingness to accept statistical estimates of how things like controlled water heaters, controlled air conditioners and so on, affect the load shape, and have that credited back against the ultimate bill that the load-serving entity or the utility or the standard offer provider makes.

There almost certainly -- well, let me state that more weakly -- there probably are some economics there. There are probably cases where it really makes sense to do that sort of thing. If you can cycle off a water heater on the hottest day in August, the customer is not going to care, the benefits are going to be real.

The only way we can do it, as a practical matter, is to accept an estimate of the impact on that, coming back to the billing system. And that will, I believe, ultimately come -- is ultimately in your ball park.

At what point do we accept the potential for errors in billing? So that's --

COMMISSIONER BROWNELL: I'm just going to ask you to wrap up, only because we have others.

MR. AUSTIN: I'm sorry.

COMMISSIONER BROWNELL: That's okay, but we have another.

MR. AUSTIN: I apologize.

Just one last comment: I mean, it is a difficult issue because half of the problems are yours and half of the problems are ours. In the end, I think probably the best solution is to for you to worry less about our particular problems, get the wholesale prices right.

If that means volatility; it means volatility. There are ways of dealing with volatility on the other side, either in terms of hedging or in terms of any number of tricks in retail rate design, to the extent we need to do it, but if you don't give us that fairly clearly price signal in the first place, we won't have the option of creating it, and that will result in uneconomic decisions. Thanks.

COMMISSIONER BROWNELL: Mr. Bartone?

MR. BARTONE: Thank you, Commissioner. I'll keep it real brief. My name is Erik Bartone, and I'm the President and founder of NXEGEN, Inc.

NXEGEN is an energy service provider located in Middletown, Connecticut. We have developed a low-cost, wireless demand management technology that we have currently deployed at a number of facilities in Connecticut.

We seek to operate within a competitive wholesale market, not just on a emergency or as-needed basis, but on a consistent and active basis. One of the panel members on the first panel raised a real good point when he said you can't build a business around emergency response, and he's absolutely 100 percent correct.

As Henry mentioned, the 2002 data for ISO New England, the price response program which is essentially a day-ahead program which I believe is an economically-driven market program, was only activated on 12 days this year for 129 hours.

Curtailment payments totaled $75,000 for the ten days in June and July, including a $32,000 payment on August 14th when the energy clearing price reached $1,000 a megawatt hour.

It's difficult to build a business plan around rules like that. To attract long-term investment in demand management solutions and have active and integrated customer participation markets, rules must be in place where demand can participate on an hourly and daily basis.

Program designs and rules must differentiate between emergency needs and the creation of active supply-and-demand market. It's NXEGEN's opinion that emergency programs will most likely require incentives and subsidies above market clearing prices.

However, efficient economic programs that allow constant and continuous participation in most cases and in most likelihood, won't require incentives or subsidization in the future.

In designing economic-based DR programs, NXEGEN is sensitive to other market participants' interests. Our belief is fundamental: Those that benefit from demand participation should be the ones bearing the costs.

The rules to enable this still don't exist today, and they require the participation of not only FERC, but the states as well, to enable rules to take place to allow this to happen.

Just to summarize, NXEGEN has seen a significant customer growth in Connecticut. We currently serve over 500 mil market customers using our technology. Those 500 customers represent about 30 megawatts of energy.

These customers range from large municipalities like the City of New Haven, to the Stamford Twin Rinks, an ice skating facility in Stamford, Connecticut, to convenience and gas stations located throughout the state.

We currently utilize the technology to manage, on an ongoing basis, demand and kilowatt hour savings for these customers, but we do not currently participate in the ISO DR programs for the simple reason that there is a cost-benefit issue related to the existing rules in today's market.

NXEGEN doesn't believe that subsidies need to be part of the market design rules. All it asks is that it operate the market that allows customers to freely participate in the market on active and ongoing basis. That's my presentation, and I'd love to open it up to questions, if there are any.

COMMISSIONER BROWNELL: Thank you. I'm sure there will be a thousand when we all get back to our offices, but we know where to find you.

MR. BARTONE: Thank you.

COMMISSIONER BROWNELL: Mr. Swider?

MR. SWIDER: Thank you, Commissioner. I'd like to thank the Commission for inviting me to speak on this panel today.

I also have a presentation, so I'll move on. I'm Michael Swider. I'm the Manager of Federal Regulatory Affairs for Strategic Energy. We're a retail electric supplier, and we are supplying in many markets across the country, including in the New England Area where we are a member of the New England Power Pool.

And we aggregate customer load; we sometimes individually manage customer load. We have a full-time energy management center for doing that. When we first got into this business, one of the first states we were operating in was in California.

And when things opened up, especially in San Diego Gas and Electric, and they went to really real-time price, we were able to offer a load-response program. We call it the Power Release Rewards Program, which is basically we had some customers who would agree that in advance of the day, we could -- we would call them up and offer it to them, to basically sell their power that we had already procured from them, back into the market.

That was a very simple load-response program that didn't require a lot of technology. It didn't require the California ISO to be involved; it was just pure, simple demand response to an unmitigated price.

Unfortunately things got a little too out of control there, and that is no longer happening, although we are still serving load in California and still active there in their demand-response initiatives.

We are looking to participate in the New England ISO's demand response program. We have partnered with a CSP there. And unfortunately, weren't able to get it up and running for this summer.

There are a lot of technical issues there, and there's even some business issues which in the end held us up I think this year where we realized that as we were putting this together, oh Jeez, our actual -- our CSP or our curtailment service provider is in a sense a competitor. And that adds an interesting wrinkle. We needed to address that before we moved ahead, but we will be participating in the ISO's programs by next summer.

Looking at the question of why isn't there more demand response, I think several panelists have mentioned this today, it's when you constrain prices, you're going to get -- you're not going to get the behavior you would expect during unconstrained prices. So prices are mitigated, and that reduces some of the incentive to participate in these programs, and not only the wholesale prices are mitigated, but many customers in fact I think most customers are still on some sort of utility rate which is not really very cost based, and even if it is semi-cost based, often a lot of the costs are hidden in wires charges and deferrals.

Customers also lack information. Tom just mentioned it. Others have mentioned it. The system wasn't designed to give out price signals. A lot needs to be done on the distribution end to get more and more smart metering installed so customers not only know what their load is but they know what the price is.

And again, I've already touched on it. There's a lack of consumer awareness and there's also a lack of operational readiness. I think last year the ISO New England program, they had a lot of bugs. This year they're got their bugs out but now we've got bugs.

There's some hoops jump through to get used to some new things, and you've got to get used to some new relationships, like, for example, partnering with somebody. We're not really designed to do this. We had to partner with somebody because of the complexity of these programs, because it's a subsidy-driven program and not really a market signal-driven program, it adds to the complexity. It makes it a little harder to participate.

Short-term solutions. Because of the technology problems and because of the lack of price signals, we don't really see how you can get beyond the current programs which, although inefficient, at least are getting the ball rolling, getting customers, more and more customers involved and introducing some new technologies that can be used when hopefully we get to what is we hope the long-term solution, which is to get the price signals out there.

You don't have to get those to perhaps everybody, but certainly there's a lot of sophisticated customers out there that you don't need to price cap, you don't need to be mitigating their price. They're quite capable of doing this on their own, and once the prices reflect the scarcity value of those more sophisticated customers. And as the technology gets better, more and more customers will be able to have this level of sophistication, will be able to participate in the market and protect themselves, and then you'll get the feedback loop that will send the right price signals out there.

And that is probably the most important issue. And if we don't get there, I think our concern is that just continued mitigation and continued subsidization really skews the whole relationship with the customer where it's no longer profitable to be selling energy management to a customer but only profitable to be selling load control, because that's where the money is. You're throwing dollars into load control, but you're not allowed to make any money on managing procurement.

COMMISSIONER BROWNELL: Thank you. Steve?

MR. RODGERS: I had just one or two questions if I could. Henry, I noticed that you had mentioned in your presentation that you were going to be doing a comprehensive, independent evaluation of the ISO New England program for 2002.

And I was wondering if as a part of that you were going to be doing an assessment of the smart metering needs that might just refer to the need for more enabling technology that's been referred to on the panel, and if you could tell me more about what the scope of your evaluation is going to include.

MR. YOSHIMURA: Sure. In our written comments, we detailed at least the goals of our evaluation. In terms of -- in general, what we're looking at is trying to estimate the costs and benefits from a resource perspective of these programs, what impact the program had on short-term pricing and that sort of thing.

But also, you know, looking at supplemental incentives being given to customers that we as the ISO may not be aware of but, for example, in New York and other states and I'm sure in the states that we serve, there are incentives being given for monitoring and metering equipment, on-site generation upgrades, that sort of thing, sign-up bonuses.

So we're looking at this thing very broadly. In terms of the specific issue of evaluating the need for smart technology, that wasn't a specific thing that we have in the scope of work of our evaluation, though one thing that we're trying to do is get at what are the common attributes across all the program participants that would tell us something about how satisfied they were with the program and what would make it better.

So insofar as implementation of these technologies is one of those things that program participants and also nonparticipants would say that's what we need to increase participation or to, you know, make the program better, then we should pick that up in our evaluation.

It's basically, in addition to the analysis and costs of benefits, there's surveys. We're doing surveys and we're also doing focus groups to get at these issues. So, hopefully, we will get that information. If that's what's important to get people involved, then we should pick that up.

MR. RODGERS: And this is an independent entity that's doing these surveys and going to give the ISO a recommendation?

MR. YOSHIMURA: That's correct. It's an independent contractor.

MR. RODGERS: Okay. And do you have idea as to when that will be done?

MR. YOSHIMURA: It's started. We're hoping to have preliminary results in December, and we're hoping, you know, to get this done by December, but that's the general timeframe. At least we'll have some information in December to inform us of whether or not we need to make some modifications going forward.

MR. RODGERS: Okay. I had one housekeeping matter I wanted to mention, Commissioner, if I could. There are several pending dockets before the Commission that involve ISO New England cases and also PJM cases that relate to demand-response issues.

So I wanted to indicate that Staff intends to have a notice issued providing an opportunity for comments for parties that are involved in those proceedings to file comments within two weeks on the specific issues that are still outstanding in those proceedings and that were touched on in any of the panelists' comments today. Those docket numbers are ER02-1326 Sub. 001 and Sub. 002. That was a PJM docket. And then the New England dockets are ER02-2330, Sub. 000 and then EL00-62-039.

In addition, Staff intends to put a copy of the relevant portion of the transcripts in the records of those proceedings. I had spoken with Susan Court about that, and she recommended that we proceed accordingly.

COMMISSIONER BROWNELL: Thanks for keeping us honest. And if there are no more questions, thanks to the panel. We appreciate again your patience with all of us as we've muddled through the day.

SECRETARY SALAS: And now the final panel the day is Panel Number 4, New England Demand Response Initiative, with Scott Miller from our FERC Staff, Eric Wong, also from FERC, and David LaPlante, Vice President of Market Development, ISO-NE.

For this panel let me note for the record that Commissioner Michael Dworkin was also going to participate but he already has done so in the morning.

COMMISSIONER BROWNELL: If we want to start, and I think the purpose is to give us a briefing on the project that Commissioner Dworkin spoke of this morning. And once again, we thank the New England participants, particularly the leadership of the commissioners, for actively taking us up on our offer. Maybe we could have a little competition between regions.

MR. MILLER: Thank you, Chairman Brownell. Staff has sent you a memo basically updating you on the status of what we're calling a collaborative of an effort between the Commission, NECPUC and the ISO New England and several other participants.

But basically, there's long been a recognition of the import of demand response, but the general view in the past has been that there isn't much that wholesale markets should be doing to facilitate that. SMD is probably a departure from that viewpoint. And I think given our experience of late, rightly so.

While most aspects of demand response still do reside within state jurisdiction, I think we've learned that wholesale market design is crucial to facilitating demand response.

But again, there has to be some sort of link-up between SMD and the state programs, and that is why at your invitation to the New England Conference of Public Utility Commissions, we have launched into a collaborative with NECPUC and ISO New England through the NEDRI process, the process which had been in existence beforehand, to try to:

1. Solicit some very meaningful input into our SMD rulemaking procedure as to what is necessary in SMD and wholesale markets to facilitate demand response.

2. A commitment from the states that they will on a regional basis attempt to adopt programs that will be in place for a considerable period of time and that will be as much as possible adopted by all the states in the region so that demand response can be effective, and to do this as rapidly as possible, hopefully that we can have some programs in place by 2003.

And again, we've taken advantage of a process that was already in existence, the NEDRI process, New England Demand Response Initiative process. And I don't want to belabor the point, given the time and the lateness of the day, and that Chairman Dworkin did already brief us on his perspectives.

But let me just say in conclusion of my remarks before I turn it over to David LaPlante that this effort couldn't have gotten where it has from FERC's standpoint without Alison Silverstein's efforts and nudging. She is the demand response yenta. And we're also pleased to have with us the expertise of Eric Wong, who is FERC's first technology fellow, and has a longstanding experience both with the California Energy Commission, WAPA, and most recently with a number of distributed generation companies. Because we know distributed generation is a corollary to demand response.

I'd also like to say that I'm very grateful to Bill Hederman for allowing Bernardo Piereck to be detailed from OMOI Staff to assist us in this effort as well too. And with that, I'd like to turn it over to David for his remarks.

MR. LaPLANTE: Thanks, Scott. Again, we appreciate the Commission's attention to this issue, having operated a market that didn't work well for three years, we realized that demand response could get us out of a lot of problems. And we're pleased to support NEDRI effort and the joint FERC-New England effort.

I did want to note that we have gotten our demand response department up and running. We're excited to have Henry with us, and we were lucky to get him.

The NEDRI effort has already borne some fruit. Yesterday we spent the day reviewing the current ISO New England proposals. There have been some modifications and improvements proposed, and hopefully we'll be bringing those down to the Commission in a timely way so that you can respond in a timely way to get the programs on the street.

I would like to reemphasize the points that were made earlier about the need for a timely definition of programs and approval. In 2001, programs didn't get down here until early spring, so they were approved in a timely way in late spring, but that was too late, really, for the participants to do much with them.

In 2002, we got them down here in early winter, they were approved at the beginning of the year, and we had much more success in 2002 than in 2001, so timely approval really does matter a lot.

I think that we're finding through the NEDRI process, many of the things that people have identified, the retail rate and standard market design has great deal to do with the success of demand response. We hope to come up with some tariffs that the New England states can use.

The other issue that we've talked a lot about is the demand response infrastructure and metering. There is a lot of concern on the part of demand-response providers that they're not treated equally with suppliers. Perhaps one way of thinking of metering and other communication infrastructure needed for demand response is the equivalent of the transmission system for generation.

And it may be worth considering rolling investments in that into either the transmission or the distribution utility rates, so maybe we can come up with some proposals in the NEDRI process to try and do that.

I guess we're moving ahead, and hopefully we'll have some results in 2003, and look forward to continuing this effort.

COMMISSIONER BROWNELL: Mr. Wong?

MR. WONG: I'll be brief. Commissioner, I appreciate the opportunity to speak, and I'm going to give you my observations. I have been involved in this process for about a month now, and I have been following the NEDRI process very closely, and I have to say there's something that's missing.

I'll give you my two observations first, and then I'll lead to that. My first observation is that the day-ahead and the day-of programs are reactive. They are much like just-in-time inventory programs, and like the West Coast dock strike, that shows you what happens if you have a shortage.

And while the analogy may not be on all fours, and I really think that the three ISOs are making great strides and making tremendous progress in this area.

The other observation that I would make is that the low prices and the number of shortages episodes, particularly this past summer, do not justify customers to go out and seek new distributive generation. So it's looking at existing programs, so I've been led to finally conclude, after having done some of this research in my past lives, that the missing component is actively planning, rather than being reactive -- actively planning for clean distributive generation, whether it's combined heat and power, or other power generation sources that can be integrated as alternatives to transmission, particularly in constrained areas, but can be explicitly, directly integrated into the planing process.

Then you can have a robust market. You have certainty to customers, to load-serving entities, to CSPs; you have certainty that's provided to the ISOs, but then you have what I view as competition because the customers will go out and seek these alternatives to provide energy to them, and they will build them in ways to meet demand response.

They can do that in modular units, and they can provide, as other speakers have said, other spinning reserves; they can bid into ancillary markets that can provide the reserve margins that are required.

So, I think that the standard market design is heading in the right direction, but the states, the ISOs, and the FERC need to work together to look at that other part of the equation, which today, at least in my observations, is missing. And those are my comments, thank you.

COMMISSIONER BROWNELL: Thank you. Thank you everyone for participating. I take away from this, that we still have work to do. I would remind everyone what this panel has just suggested, and that is, what we are doing in SMD and what we are doing at the FERC is not to replace or be in competition with the state commissions and their authority over retail programs, but, indeed, to be a platform to support those, and, indeed, to introduce demand-side programs and technology into the market as an equal player, rather than the program of the moment.

Further, I'd love to see and hear more about the enabling technologies, including more on distributed generation, because I think that's a large part of the solution that maybe we don't fully understand.

So I appreciate what we've learned here today, and I do want to say, on behalf of the Chairman and Commissioner Breathitt, they did have another obligation, so, I know they will be back and will be getting debriefed, and we all recognize this, and I think you've all heard us speak about the importance of this as the markets grow, and we, indeed, get to real markets.

I wanted to also announce, consistent with the Chairman's reference at our September 8th meeting, that the Commission will conduct its second Hydro Licensing Status Workshop next month on November 8th. The workshop will be held here in the Commission meeting room from 10:00 to 4:00.

Again, we will focus on the hydro project license applications pending before the Commission for five years or longer -- amazing, five years or longer. The workshop will, again, concentrate on identifying the unresolved issues associated with each project, and in determining the best course of action to resolve or remove obstacles to the final action. We'll publish a notice soon that will list the project and other details.

I would suggest that this was enormously successful, I think, in identifying a lot of the problems between and among the agencies. We were informed, I think, a great deal by the last hearing, and look forward to this one as we look forward to the Notice of Proposed Rulemaking and working with our fellow agencies in identifying administrative solutions to a system that is, at best, flawed. Thanks. Thank you everyone, and the meeting is adjourned unless there is further business.

(No response.)

COMMISSIONER BROWNELL: Thank you.

(Whereupon, at 3:25 p.m., the meeting was adjourned.)